UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

PETITION OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
FOR APPROVAL OF PROPOSED RELIABILITY STANDARD
BAL-003-2

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] the North American Electric Reliability Corporation ("NERC")[3] hereby submits proposed Reliability Standard BAL-003-2 – Frequency Response and Frequency Bias Setting for Commission approval. Proposed Reliability Standard BAL-003-2 enhances reliability and improves upon the currently effective version of the standard by refining and clarifying the process and methods for calculating the amount of Frequency Response that must be provided in a given operating year to support the reliable operation of the Bulk Power System.[4] Additionally, the proposed standard provides NERC with increased flexibility to incorporate additional refinements to the annual process as future lessons are learned.

NERC requests that the Commission approve proposed Reliability Standard BAL-003-2 (**Exhibit A**) as just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC also requests approval of the associated implementation plan (**Exhibit B**) as detailed in this

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[1] 16 U.S.C. § 824o (2018).

[2] 18 C.F.R. § 39.5 (2019).

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

[4] Unless otherwise indicated, capitalized terms used in this petition shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards* ("NERC Glossary"), https://www.nerc.com/pa/Stand/Glossary%20of%20Terms/Glossary_of_Terms.pdf.

petition, the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (**Exhibit C)**, and the retirement of currently effective Reliability Standard BAL-003-1.1.

As required by section 39.5(a) of the Commission's regulations,[5] this Petition presents the technical basis and purpose of the proposed Reliability Standard, a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672[6] (**Exhibit D**), and a summary of the standard development history (**Exhibit I**). The proposed Reliability Standard was adopted by the NERC Board of Trustees on November 5, 2019.

Additionally, NERC submits the revised *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* (or "*Procedure*") for the information of the Commission (**Exhibit E)**. The *Procedure* supports proposed Reliability Standard BAL-003-2.

I. <u>SUMMARY</u>

Frequency Response is a measure of an Interconnection's ability to stabilize frequency immediately following the sudden loss of generation or load. As such, it is a critical component to the reliable operation of the Bulk Power System, particularly during disturbances and restoration.[7] Power system operators manage or control frequency primarily through adjustments to generator output intended to restore balance between generation and load. Failure to maintain frequency can disrupt the operation of equipment and initiate disconnection of power plant equipment to prevent them from being damaged, which could lead to wide-spread blackouts.

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[5] 18 C.F.R. § 39.5(a).

[6] The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC ¶ 61,104, at PP 262, 321-37, *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006) ("Order No. 672").

[7] System frequency reflects the instantaneous balance between generation and load. Reliable operation of a power system depends on maintaining frequency within predetermined boundaries above and below a scheduled value, which is 60 Hertz ("Hz") in North America.

Currently effective Reliability Standard BAL-003-1.1 provides requirements which are designed to ensure sufficient Frequency Response from Balancing Authorities to maintain Interconnection frequency within predefined boundaries by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. The standard is intended to provide consistent methods for determining the amount of Frequency Response needed in each Interconnection as well as measuring Frequency Response performance.

Attachment A to the standard discusses the establishment of the Interconnection Frequency Response Obligation ("IFRO"). The IFRO is the minimum amount of Frequency Response that must be maintained by an Interconnection. Attachment A also describes the process the ERO follows to validate the Balancing Authority's Frequency Response Standard ("FRS") Form 1 data and publish the official Frequency Bias Settings. FRS Form 1 provides the instructions and calculations to measure Frequency Response performance at the Balancing Authority level. The *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*, or *Procedure*, outlines how the ERO conducts a transparent process annually to identify a list of frequency events to be used by Balancing Authorities to calculate their Frequency Response performance to assess whether the Balancing Authority met its Frequency Response Obligation and to determine an appropriate Frequency Bias Setting.

Supporting documents for the currently effective standard were developed using engineering judgment on the data collection and process needed to determine the IFRO, as well as the processing of raw data to assess compliance. In the course of implementing the standard, NERC identified minor implementation issues and process inefficiencies. Further, it was anticipated that as Frequency Response improves, the approaches embedded in the standard for collecting annual samples would need to be modified.

Proposed Reliability Standard BAL-003-2 improves upon currently effective Reliability Standard BAL-003-1.1 by addressing these issues through a series of targeted revisions to Attachment A, the related forms, and supporting *Procedure.*

Specifically, and as discussed further herein, these revisions:

- Address issues related to frequency performance calculations in the currently effective standard, which could result in the IFRO values being increased year over year despite improved performance, or being decreased despite worsened performance;

- Provide a repeatable and consistent method for determining the Interconnection Resource Contingency Criteria (now referred to as the "Resource Loss Protection Criteria" or "RLPC") for all Interconnections; the RLPC reflects the Interconnection design resource loss which is used to determine the IFRO; and

- Clarify language related to Frequency Response Reserve Sharing Groups and the timeline for Frequency Response and Frequency Bias Setting activities.

To allow NERC to make timely process improvements in the future as new lessons are learned, NERC has removed some procedural detail from Attachment A and included it in the *Procedure*. The FRS Form 1 has also been revised to support the new data required by the proposed standard and revised *Procedure.*

Collectively, these revisions will enhance the effectiveness of the BAL-003 Reliability Standard and thereby advance the reliability of the Bulk Power System. NERC respectfully requests that the Commission approve proposed Reliability Standard BAL-003-2 and the associated implementation plan as just, reasonable, not unduly discriminatory or preferential, and in the public interest.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[8]

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III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[9] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Bulk Power System, and with the duties of certifying an Electric Reliability Organization ("ERO") that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1) of the FPA states that all users, owners, and operators of the Bulk Power System in the United States will be subject to Commission-approved Reliability Standards.[10] Section 215(d)(5) of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard.[11] Section 39.5(a) of the Commission's regulations requires the ERO to file with the Commission for its approval each new Reliability Standard that the ERO proposes should

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

[9] 16 U.S.C. § 824o.

[10] *Id*. § 824o(b)(1).

[11] *Id*. § 824o(d)(5).

become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.[12]

The Commission is vested with the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk Power System and to ensure that Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA and Section 39.5(c) of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.[13]

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[14] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of the NERC Rules of Procedure ("ROP") and the NERC Standard Processes Manual ("SPM").[15]

In its order certifying NERC as the ERO, the Commission found that NERC's rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance

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12 18 C.F.R. § 39.5(a).

13 16 U.S.C. § 824o(d)(2); 18 C.F.R. § 39.5(c)(1).

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

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

of interests in developing Reliability Standards,[16] and thus satisfy the criteria for approving Reliability Standards.[17] NERC's standard development process is accredited by the American National Standards Institute and is open to any person or entity with a legitimate interest in the reliability of the Bulk Power System. Stakeholders must approve, and the NERC Board of Trustees must adopt, a Reliability Standard before NERC submits the Reliability Standard to the Commission for approval.

C. Procedural History

1. History of the BAL-003 Reliability Standard

In Order No. 693, issued on March 16, 2007, the Commission approved the NERC Resource and Demand Balancing Reliability Standards, including Reliability Standard BAL-003-0. In this Order, the Commission directed NERC to develop modifications that would, among other things, "define[] the necessary amount of Frequency Response needed for Reliable Operation for each balancing authority with methods of obtaining and measuring that the frequency response is achieved."[18]

In response to this directive, NERC developed Reliability Standard BAL-003-1, which was approved by the Commission in Order No. 794 issued January 16, 2014.[19] In approving the standard, the Commission found that it "addresses an existing gap in reliability and the Commission's directives set forth in Order No. 693."[20] The Commission directed NERC to "submit two reports, and to continue its ongoing analysis of certain aspects of BAL-003-1 to

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16 Order No. 672 at P 268.

17 *Id*. at PP 268, 270.

18 *See Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, 118 FERC ¶ 61,218 at P 375, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

19 *Frequency Response and Frequency Bias Setting Reliability Standard*, Order No. 794, 146 FERC ¶ 61,024 (2014) ("Order No. 794").

20 *Id*. at P 1.

address concerns regarding specific provisions of the Reliability Standard and to determine the effectiveness of Reliability Standard BAL-003-1 in providing an adequate amount of frequency response."[21] The Commission stated that, depending on the results and recommendations of the reports, further refinements to the standard may be warranted.[22] Additionally, the Commission directed NERC to revise the Violation Risk Factor and Violation Severity Levels for Requirement R1.[23]

On August 29, 2014, NERC submitted for Commission approval the directed VRF and VSL revisions for Requirement R1 of Reliability Standard BAL-003-1.[24] The Commission approved the revisions on November 26, 2014.[25] The Commission approved errata version Reliability Standard BAL-003-1.1 on November 13, 2015.[26]

2. Order No. 794 Informational Filings

As noted in the preceding section, in Order No. 794 the Commission directed NERC to submit two reports. On June 30, 2017, NERC submitted the first of the reports directed by Order No. 794, addressing the results and recommendations of a light-load case study of the Eastern Interconnection.[27] On June 29, 2018, NERC submitted the second of the reports directed by Order No. 794, addressing: (1) an evaluation of the use of the linear regression methodology to calculate

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[21] *Id*. at P 3 (internal citation omitted).

[22] *Id*. at P 3.

[23] *Id*. at PP 90, 95.

[24] Revisions to the Violation Risk Factors and Violation Severity Levels to Certain Reliability Standards, Docket Nos. RM12-1-000, RM13-9-000, RM13-11-000, and RM13-16-000 (Aug. 29, 2014).

[25] Revisions to the Violation Risk Factors and Violation Severity Levels to Certain Reliability Standards, Docket Nos. RM12-1-000, RM13-9-000, RM13-11-000, and RM13-16-000 (Nov. 26, 2014) (delegated letter order).

[26] N. Am. Elec. Reliability Corp., Docket No. RD15-6-000 (Nov. 13, 2015) (delegated letter order).

[27] Order No. 794 at P 3; *Informational Filing of the North American Electric Reliability Corporation Regarding the Light-Load Case Study of the Eastern Interconnection*, Docket No. RM13-11-000 (filed June 30, 2017).

frequency response; and (2) the availability of resources for applicable entities to meet the Frequency Response Obligation.[28]

3. Frequency Response Annual Analysis

Each year, NERC files with the Commission on an informational basis its annual report for the administration and support of Reliability Standard BAL-003-1.1 titled the Frequency Response Annual Analysis ("FRAA").[29] The FRAA contains the annual analysis, calculation, and recommendations for the IFRO for each of the four electrical interconnections of North America for the coming operational year (December through November).

4. *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*

The revised *Procedure*, attached to this filing as **Exhibit E**, represents the first revision to this document since its initial submission to the Commission as part of NERC's petition for approval of proposed Reliability Standard BAL-003-1.[30] NERC must file with the Commission on an informational basis any revisions to the *Procedure* in accordance with the revision process set forth in that document.[31]

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28 Order No. 794 at P 3; *Informational Filing of the North American Electric Reliability Corporation*, Docket No. RM13-11-000 (Jun. 29, 2018).

29 The 2012 *Frequency Response Initiative Report* was included as Exhibit F to NERC's March 29, 2013 petition for approval of BAL-003-1. Reports for subsequent years were submitted to the Commission in Docket No. RM13-11-000 as follows: (i) 2014 FRAA, submitted March 20, 2015; (ii) 2015 FRAA, submitted December 16, 2015; (iii) 2016 FRAA, submitted October 21, 2016; (iv) 2017 FRAA, submitted November 29, 2017, (v) 2018 FRAA, submitted November 29, 2018; and (vi) 2019 FRAA, submitted November 21, 2019.

30 *See* Petition of NERC for Approval of Proposed Reliability Standard BAL-003-1 – Frequency Response and Frequency Bias Setting, Docket No. RM13-11-000 (Mar. 29, 2013) at Exhibit C.

31 *See* **Exhibit E** (revised *Procedure*) at iv (describing the revision process for the *Procedure,* which provides that any changes must be accompanied by a technical justification, must be posted for a 45-day formal comment period, must be discussed in a public meeting, and must be submitted to the NERC Board of Trustees for adoption; additionally, any changes shall be filed with the Commission for informational purposes).

D. Development of the Proposed Reliability Standard

This section provides an overview of the procedural history of proposed Reliability Standard BAL-003-2.

1. 2016 FRAA Report

In the course of preparing the 2016 FRAA, NERC identified what it called "inconsistencies" in IFRO calculations under Reliability Standard BAL-003-1.1. Due to these issues, NERC recommended maintaining the 2016 IFRO values for operating year 2017.[32] NERC also recommended that the NERC Resources Subcommittee "develop a Standard Authorization Request (SAR) to revise the IFRO calculation in BAL-003-1 due to inconsistencies identified in the 2016 [FRAA] such as the IFRO values with respect to Point C and varying Value B, the Eastern Interconnection Resource Contingency Protection Criteria, event selection criteria, and evaluation of t_0."[33]

Additionally, Recommendations 3 and 4 of the report recommended as follows:

> 3. The Resource Contingency Protection Criteria for each interconnection should be revised to help ensure sufficient primary frequency response is maintained. The Eastern Interconnection uses the "largest resource event in [the] last 10 years", which is the 4 August 2007 event. The Standard Authorization Request (SAR) should revisit this issue for modifications to [the] BAL-003-1 standard, and the Resources Subcommittee should recommend how the events are selected for each interconnection.
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> 4. Many events, particularly in the Eastern Interconnection due to its large synchronous inertia, tend to have a frequency nadir point that exceeds the t_0+12 seconds specified in BAL-003-1. Therefore, some events are characterized with a Point C value that is only partially down the arresting period of the event and does not accurately reflect the actual nadir. BAL-003-1 should be modified to allow for accurate representation of the Point C nadir value if exceeding t_0+12

32 2016 FRAA at v.

33 *Id*. at v, Recommendation 2.

> seconds. The actual event nadir can occur at any time, including beyond the time period used for calculating Value B (t_0+20 through t_0+52 seconds), and may be the value known as Point C' which typically occurs from 72 to 95 seconds after t_0.[34]

The 2016 FRAA was filed with FERC on October 21, 2016.[35] Subsequent year FRAA reports continued to identify these issues and recommended that they be addressed, while maintaining 2016 IFRO values in the meantime.

2. Procedural History of Project 2017-01 Modifications to BAL-003-1.1

As recommended by the 2016 FRAA Report, the NERC Operating Committee Resources Subcommittee developed a Standard Authorization Request to develop modifications to Reliability Standard BAL-003-1.1. The Standard Authorization Request was posted from June 19, 2017 through July 18, 2017. A second Standard Authorization Request was submitted by Northwest Power Pool recommending that the project add a second phase to address additional issues. The second request was posted for comment from November 2, 2017 through December 1, 2017.

The project was thereafter broken out into two phases. The purpose of the first phase was to address the recommendations of the 2016 FRAA report to address IFRO calculation issues, primarily though targeted revisions to BAL-003-1.1 Attachment A and the supporting documents. The purpose of the second phase is to address broader potential revisions to BAL-003 requirements, including consideration of the IFRO method in its entirety and revisions to the applicable entities.

Following one informal comment period and one formal 45-day comment period and ballot, the final draft of proposed Reliability Standard BAL-003-2 was approved by the ballot pool on October 24, 2019. The proposed standard received 100 percent weighted segment approval with

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34 *Id*. at v, Recommendations 3-4 (internal citation omitted).

35 *See supra* n. 29.

92.96 percent quorum. Revisions to the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* and FRS Form 1 were posted alongside the draft BAL-003-2 standard. The revised *Procedure* was discussed in two public meetings and was presented to the Operating Committee for informational purposes on March 5, 2019.[36] On November 5, 2019, the NERC Board of Trustees adopted proposed Reliability Standard BAL-003-2 and the revised *Procedure*, thus officially concluding work under the first phase of Project 2017-01. Work under the multi-year second phase of the project remains ongoing.

IV. <u>JUSTIFICATION FOR APPROVAL</u>

As discussed below and in **Exhibit D**, proposed Reliability Standard BAL-003-2 improves upon currently effective Reliability Standard BAL-003-1.1 by enhancing the processes for the calculation of IFROs to eliminate unintended counter-incentives and improving the effectiveness of the standard, thereby advancing the reliability of the Bulk Power System. As discussed below, no changes are proposed to the purpose, applicability, or requirements. Substantial revisions are proposed in Attachment A, as administrative items associated with implementation of the standard were recommended for movement from the standard itself into the *Procedure*. Additionally, the supporting forms and the *Procedure* have been revised accordingly.

In this section, NERC provides: (a) a brief overview of the proposed standard; (b) a description of each of the changes in the proposed standard and, where appropriate, corresponding revisions to the *Procedure*; and (c) discussion of the enforceability of the proposed standard.

A. Overview of Proposed Reliability Standard BAL-003-2

The purpose of proposed Reliability Standard BAL-003-2, which remains unchanged from currently effective Reliability Standard BAL-003-1.1, is "[t]o require sufficient Frequency

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[36] *See* NERC, *Meeting Minutes – Operating Committee* (March 5-6, 2019), Agenda Item 15 at 17, https://www.nerc.com/comm/OC/Pages/AgendasHighlightsandMinutes.aspx.

Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting." The proposed standard would continue to apply to Balancing Authorities and Frequency Response Sharing Groups.[37]

Proposed Reliability Standard BAL-003-2 consists of the following four requirements, which remain unchanged from the currently effective version:

- Requirement R1 specifies that each applicable entity shall achieve an annual Frequency Response Measure (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation to ensure that sufficient Frequency Response is provided by each applicable entity to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation.

- Requirement R2 specifies that 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 in accordance with Attachment A, as validated by the ERO, into its Area Control Error calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO.

- Requirement R3 specifies that each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: (1) less than zero at all times, and (2) equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.

- Requirement R4 specifies that each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its Area Control Error calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority Area, to be equivalent to either: (i) the sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO; (ii) the Frequency Bias Setting

[37] A Frequency Response Sharing Group is defined in the NERC Glossary as "a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members."

> shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.

The revisions in proposed Reliability Standard BAL-003-2 are concentrated in Attachment A to the standard, BAL-003-2 Frequency Response and Frequency Bias Setting Standard Supporting Document, which is referenced in Requirements R1 and R2. Revisions are also made to the FRS Form 1 referenced in Requirement R4 and Attachment A, as well as the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*, referenced in Attachment A. These revisions are discussed in detail in the following section.

B. Justification for Proposed Reliability Standard BAL-003-2

This section discusses the revisions reflected in proposed Reliability Standard BAL-003-2, including corresponding revisions to the associated *Procedure*, and how these revisions improve the effectiveness of the BAL-003 Reliability Standard. These revisions are grouped as follows: (1) revisions to the calculation of Max Delta Frequency; (2) revisions to the methods used to determine the Interconnection Resource Loss Protection Criteria; (3) clarifying revisions; and (4) revisions to the *Procedure* to select Frequency Response Standard excursion events for analysis.

1. Calculation of Max Data Frequency

Proposed Reliability Standard BAL-003-2 streamlines Table 1 in Attachment A and removes multiple data frequency lines that were intended to be used in the calculation of IFROs. The purpose of these revisions is to address certain issues that were identified in the 2016 FRAA related to the application of these values; specifically, that application of these values could have the unintended effect of penalizing an Interconnection, by means of a higher IFRO, for improved performance, while rewarding an Interconnection, by means of a lower IFRO, for decreased performance. Proposed Reliability Standard BAL-003-2 addresses this issue by revising Attachment A, Table 1 and related supporting materials by removing all frequency lines but the

Max Delta Frequency. The revised *Procedure* defines Max Delta Frequency as that defined for the specific Interconnection in the 2017 FRAA. In the future, NERC would pursue any changes to the process for defining the Max Delta Frequency through the open and transparent revision process set forth in the *Procedure*. This would allow for more timely incorporation of necessary adjustments, such as to incorporate recommendations that result from analysis in future FRAA reports.

These revisions are necessary for the following reasons. As NERC observed in the 2016 FRAA, all of the calculations of the IFRO in the currently effective standard are based on avoiding instantaneous or time-delayed tripping of the highest set point of under frequency load shedding ("UFLS"), either for the initial nadir (Point C), or for any lower frequency that might occur during the frequency event. Because the ability to measure the frequency nadir at the Balancing Authority level is limited by the Supervisory Control and Data Acquisition scan rates available to calculate Point C, an adjustment factor (CB_R) was added to capture the relationship between Value B and Point C.

While Point C may not be captured accurately at the Balancing Authority level due to energy management system scan rates, it is captured accurately at the Interconnection level using FNet frequency data recorders. Balancing Authority performance for individual frequency events, under currently effective Reliability Standard BAL-003-1.1, is based on the change in Net Actual Interchange for that Balancing Authority from the Value A to Value B time intervals, as compared to the change in A-B frequency, as measured by that Balancing Authority. An accurate measurement of Point C at the Balancing Authority level is not necessary to measure Balancing Authority performance.

The original intent of the CB_R adjustment in the IFRO calculation was to address a scenario where A-C was increasing (arresting period performance declining), while A-B was unchanged (stabilizing period performance stable). Under this scenario, the increase in CB_R would result in an increase in the IFRO. However, what was observed in the 2016 FRAA[38] was that the CB_R (and resulting IFRO) will also increase when A-C arresting period performance is unchanged and stabilizing period performance is improving, with A-B getting smaller. It was also observed that if A-B increases (declining stabilizing period performance) and A-C is unchanged, then the CB_R would decrease, as would the resulting IFRO. Stated differently, an Interconnection could be penalized for improved Frequency Response performance as measured against Value B, or, conversely, rewarded for poor performance.

The drafting team determined that, in light of these issues, the appropriate way to address the Max Delta Frequency calculation was to place the calculation in the *Procedure*, with its value set as supported by NERC Staff analysis in the 2017 FRAA. This revision would allow for flexibility to perform additional analysis and review in future years. The revisions in proposed Reliability Standard BAL-003-2 and the associated *Procedure* thus provide a clear, but flexible, method for establishing this aspect of the IFRO calculations going forward.

2. Method Used to Determine the Interconnection Resource Loss Protection Criteria

The Interconnection Resource Loss Protection Criteria, or RLPC, is the Interconnection design resource loss measured in MW. It is used to determine the IFRO. In currently effective Reliability Standard BAL-003-1.1, this measure is referred to as the Resource Contingency Criteria (or "RCC"). As defined in Attachment A to currently effective BAL-003-1.1, this measure is based on the largest "N-2" event, defined as a single initiating event that leads to multiple

38 *See* 2016 FRAA at vii.

electrical facilities being removed from service, identified in each Interconnection except for the Eastern Interconnection. For the Eastern Interconnection, the RLPC is calculated by using the largest single event in the previous ten years.

Proposed Reliability Standard BAL-003-2 improves upon the currently effective standard as follows. Language regarding the calculation of the Resource Contingency Criteria is removed from Attachment A to the standard; the revised *Procedure* sets forth a detailed and consistent method for determining RLPCs across all Interconnections.[39] This method is further described in the associated background document, included as **Exhibit G** to this petition.

The revised *Procedure* will determine the Interconnection RLPC in accordance with a process where Balancing Authorities will provide their two largest resource loss values and largest resource loss due to an N-1 or N-2 Remedial Action Scheme event. Under this process, the calculated RLPC should meet or exceed, but never fall short of, any credible N-2 resource loss event scenario. RLPCs would be evaluated annually and would reflect changes in system conditions based on information submitted by Balancing Authorities.

NERC notes that, compared to the currently effective standard, the largest adjustment is in the proposed RLPC value for the Eastern Interconnection. The present RLPC for the Eastern Interconnection of 4,500 MW was recommended in the *2012 Frequency Response Initiative Report*[40] and reflected what had been the largest resource contingency event in the previous ten years at the time of the report: an August 2007 event that involved nine generators across three states and resulted in a loss of 4,457 MW and a frequency nadir of 59.863 Hz.

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39 *See* Exhibit E (revised *Procedure*) at Chapter 3.

40 *See Petition of NERC for Approval of Proposed Reliability Standard BAL-003-1 – Frequency Response and Frequency Bias Setting*, Exhibit F at 55, Docket No. RM-13-11-000 (Mar. 29, 2013).

Since the 2012 report was issued, the largest resource loss event in the Eastern Interconnection was a loss of 2,344 MW in April 2013. This event, however, did not represent the largest potential N-2 event for the Eastern Interconnection, which, according to the target RLPC value using 2018 data, is 3,209 MW. During the drafting process it was determined that using a consistent approach for all Interconnections, one that ensures that the RLPC meets or exceeds any credible N-2 event, would be preferable to the years-based approach for determining the Eastern Interconnection RLPC used in the current standard.

3. Revised Target IFRO Values

Proposed Reliability Standard BAL-003-2 revises the target IFRO values for each of the four North American Interconnections in Attachment A Table 1, based on the adjustments made to the frequency and RLPC calculations discussed in the previous sections. These values are appropriately labeled target values, as they remain subject to change as part of the annual review process.

During the development process for proposed BAL-003-2, NERC staff performed an independent analysis using dynamic simulations to validate the proposed target IFRO values for the Eastern, Western, and ERCOT Interconnections based on the proposed RLPC calculation formula. In performing its analysis, staff used the proposed values for RLPC, and the values from the 2017 FRAA for the Maximum Delta Frequency and Credit for Load Resources. Please refer to this report, attached as **Exhibit F** to this petition, for further information on the assumptions, methods, and data used in the analysis, as well as a detailed description of the results of the dynamic simulations. In conclusion, NERC staff's study validated the proposed IFRO calculation formula. The proposed target values for the Western and ERCOT Interconnections were successfully validated within 5 MW/.1 Hz of the IFRO that had been established through the IFRO calculation formula, with resulting minimum Point C frequency nadir above the threshold for UFLS for the respective Interconnection.[41] However, under the circumstances and assumptions of NERC staff's dynamic simulations, the calculated target IFRO for the Eastern Interconnection (-764 MW/.1Hz) appeared to be slightly lower than what would be required (IFRO -787 MW/.1Hz) to avoid under frequency load shedding.[42]

For the Eastern Interconnection, NERC proposes to implement the planned reduction in target IFRO in three increments. As provided in Attachment A, if the Interconnection Frequency Response Measure declines by more than ten percent, then NERC will halt the IFRO reduction until the cause of the degradation is identified. This measured approach will help ensure the planned IFRO reduction would not pose a risk to reliability when implemented. As an additional measure of conservatism, the final target IFRO in Attachment A Table 1 has been adjusted to reflect the IFRO value validated through NERC staff's analysis.

It is important to note that all IFRO values contained in Attachment A Table 1 are target values, not final values, and remain subject to change as determined through NERC's annual process. The IFRO values would continue to be evaluated annually based on changes in the RLPC, with the final IFRO values for the operating year adjusted as appropriate. Additionally, no reductions in IFROs would be implemented without first being validated through the use of dynamic simulations.

4. Clarifications and Other Revisions

Proposed Reliability Standard BAL-003-2 Attachment A contains several revisions to clarify the obligations of Frequency Response Sharing Groups with respect to the calculation of

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41 *Interconnection Frequency Response Obligation Determination and Validation: BAL-003-2 SDT Revised RLPC and IFRO Method*, Exhibit F, at iv (Executive Summary).

42 *Id.* at 6.

Frequency Response Measure performance. The Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities has been updated and streamlined. These changes are shown in redline in Exhibit A.

5. Other Revisions to the *Procedure* and Supporting Documents

The *Procedure* specifies the criteria to be used by the ERO to select Frequency Response Standard excursion events for analysis. In addition to the revisions to the *Procedure* discussed above in the context of associated changes to the BAL-003 standard, the Point C frequency nadir has been revised, from being defined as the "arrested value of frequency observed within **12** seconds following the start of the excursion," to the "arrested value of frequency observed within **20** seconds following the start of the excursion."[43] This revision, which responds to a recommendation from the 2016 FRAA,[44] will more accurately capture the true frequency nadir during the arresting period of an event.

Additionally, supporting FRS Form 1 has been updated to include provision of resource loss data to support the calculation of the RLPC, in accordance with the revised *Procedure*.

C. Enforceability of Proposed Reliability Standard BAL-003-2

Proposed Reliability Standard BAL-003-2 includes VRFs and VSLs. The VRFs assess the impact to reliability caused by violations of a specific requirement and are one of several elements used to determine an appropriate sanction when the associated requirement is violated. The VSLs

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43 **Exhibit E** (revised *Procedure*) at Chapter 1 (Event Selection Criteria 3.a.ii) (emphasis added).

44 *See* 2016 FRAA at v. Recommendation 4 of the 2016 FRAA stated:

> Many events, particularly in the Eastern Interconnection due to its large synchronous inertia, tend to have a frequency nadir point that exceeds the t0 3+12 seconds specified in BAL-003-1. Therefore, some events are characterized with a Point C value that is only partially down the arresting period of the event and does not accurately reflect the actual nadir. BAL-003-1 should be modified to allow for accurate representation of the Point C nadir value if exceeding t0+12 seconds. The actual event nadir can occur at any time, including beyond the time period used for calculating Value B (t0+20 through t0+52 seconds), and may be the value known as Point C' which typically occurs from 72 to 95 seconds after t0.

provide guidance on the way that NERC will enforce the requirements of the proposed Reliability Standard. The VRFs in proposed Reliability Standard BAL-003-2 are unchanged from currently effective Reliability Standard BAL-003-1.1. The VSLs for Requirements R2 through R4 remain unchanged from the currently effective standard. The VSL for Requirement R1 is revised to establish clear and progressive thresholds for the different levels of noncompliance. The VRFs and VSLs for proposed Reliability Standard BAL-003-2 continue to comport with NERC and Commission guidelines related to their assignment.

Proposed Reliability Standard BAL-003-2 includes measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. These measures, which are unchanged from the currently effective Reliability Standard BAL-003-1.1, help ensure that the requirements will be enforced in a clear, consistent, non-preferential manner, and without prejudice to any party.

V. EFFECTIVE DATE

NERC respectfully requests that the Commission approve the proposed implementation plan for proposed Reliability Standard BAL-003-2, included as **Exhibit B**. Under NERC's proposed implementation plan, Reliability Standard BAL-003-2 would become effective on the first day of the first operating year that is 90 days after the effective date of regulatory approval. NERC's operating year begins on December 1; therefore, the standard would become effective on that date. Currently effective Reliability Standard BAL-003-1.1 would be retired immediately prior to the effective date of the proposed standard. The proposed implementation plan balances the need for prompt implementation of the proposed standard while aligning its implementation with the existing BAL-003 timelines for calculation of IFRO values for the coming operating year.

VI. CONCLUSION

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

- proposed Reliability Standard BAL-003-2 and the associated elements, including the VRFs and VSLs, included in **Exhibit A**;

- the proposed implementation plan, included in **Exhibit B**; and

- the retirement of currently-effective Reliability Standard BAL-003-1.1.

Respectfully submitted,

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Counsel for the North American Electric Reliability Corporation

Date: December 19, 2019

Exhibit A1

Proposed Reliability Standard BAL-003-2
Clean

A. Introduction

1. **Title: Frequency Response and Frequency Bias Setting**

2. **Number: BAL-003-2**

3. **Purpose:** To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authority

   4.1.1.1. Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.

   4.1.2. Frequency Response Sharing Group

5. **Effective Date:** See Implementation Plan for BAL-003-2.

B. Requirements and Measures

R1. Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) 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. *[Risk Factor: High][Time Horizon: Real-time Operations]*

M1. Each Frequency Response Sharing Group or Balancing Authority that is not a member of a Frequency Response Sharing Group shall have evidence such as dated data plus documented formula in either hardcopy or electronic format that it achieved an annual FRM (in accordance with the methods specified by the ERO in Attachment A with data from FRS Form 1 reported to the ERO as specified in Attachment A) that is equal to or more negative than its FRO to demonstrate compliance with Requirement R1.

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 in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. *[Risk Factor: Medium][Time Horizon: Operations Planning]*

M2. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service shall have evidence such as a dated document in hard copy or electronic format showing the ERO validated Frequency Bias Setting was implemented into its ACE calculation within the implementation period specified or other evidence to demonstrate compliance with Requirement R2.

R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

3.1 Less than zero at all times, and

3.2 Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.

M3. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and is utilizing variable Frequency Bias shall have evidence such as a dated report in hard copy or electronic format showing the average clock-minute average Frequency Bias Setting was less than zero and during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was equal to or more negative than its Frequency Response Obligation to demonstrate compliance with Requirement R3.

R4. 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 to either: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

- The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or

- The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.

M4. The Balancing Authority shall have evidence such as a dated operating log, database or list in hard copy or electronic format showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation as specified in Requirement R4 to demonstrate compliance with Requirement R4.

C. Compliance

1. **Compliance Monitoring Process**

   1.1. **Compliance Enforcement Authority:** "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

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

   The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

   - The Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
   - The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
   - If a Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.
   - The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

   1.3. **Compliance Monitoring and Enforcement Program:** As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

      - For Interconnections that are also Balancing Authorities, Tie Line Bias control and flat frequency control are equivalent and either is acceptable.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by at most 15% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 15% but by at most 30% or 30 MW/0.1 Hz, whichever is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 30% but by at most 45% or 45 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 45% or by more than 45 MW/0.1 Hz, whichever is the greater deviation from its FRO.
R2.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting failed to implement the validated Frequency Bias Setting value into its ACE calculation within the implementation period specified but did so within 5 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 5 calendar days but less than or equal to 15 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 15 calendar days but less than or equal to 25 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting did not implement the validated Frequency Bias Setting value into its ACE calculation in more than 25 calendar days from the implementation period specified by the ERO.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 1% but by at most 10%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 10% but by at most 20%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 20% but by at most 30%.	The Balancing Authority that is a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response obligation by more than 30%.
R4.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error less than or equal to 10% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 10% but less than or equal to 20% of the	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 20% but less than or equal to 30% of the	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 30% of the validated or calculated value. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		validated or calculated value.	validated or calculated value.	The Balancing Authority failed to change the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services.

D. Regional Variances

None.

E. Associated Documents

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

FRS Form 1

FRS Form 2

Frequency Response Standard Background Document

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	March 16, 2007	FERC Approval — Order 693	New
0a	December 19, 2007	Added Appendix 1 — Interpretation of R3 approved by BOT on October 23, 2007	Addition
0a	July 21, 2008	FERC Approval of Interpretation of R3	Addition
0b	February 12, 2008	Added Appendix 2 — Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition
0.1b	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial; updated version number to “0.1b”	Errata
0.1b	October 29, 2008	BOT approved errata changes	Errata
0.1a	May 13, 2009	FERC Approved errata changes – version changed to 0.1a (Interpretation of R2, R2.2, R5, and R5.1 not yet approved)	Errata
0.1b	May 21, 2009	FERC Approved Interpretation of R2, R2.2, R5, and R5.1	Addition
1	February 7, 2013	Adopted by NERC Board of Trustees	Complete Revision under Project 2007-12
1	January 16, 2014	FERC Order issued approving BAL-003-1. (Order becomes effective for R2, R3, and R4 April 1, 2015. R1 becomes effective April 1, 2016.)	
1	May 7, 2014	NERC Board of Trustees adopted revisions to VRF and VSLs in Requirement R1.	
1	November 26, 2014	FERC issued a letter order approved VRF and VSL revisions to Requirement R1.	

Version	Date	Action	Change Tracking
1.1	August 25, 2015	Added numbering to Introduction section, corrected parts numbering for R3, and adjusted font within section M4.	Errata
1.1	November 13, 2015	FERC Letter Order approved errata to BAL-003-1.1. Docket RD15-6-000	Errata
2	November 5, 2019	NERC Board of Trustees adopted BAL-003-2	New

Attachment A

BAL-003-2 Frequency Response and Frequency Bias Setting Standard

Supporting Document

Interconnection Frequency Response Obligation

The ERO, in consultation with regional representatives, has established a target reliability criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). Preliminary values are provided below. Certain values are assessed annually according to the methodology which is detailed in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.

Interconnection	**Eastern**	**Western**	**ERCOT**	**HQ**	Units
Max. Delta Frequency (MDF)	**0.420**	**0.280**	**0.405**	**0.947**	
Resource Loss Protection Criteria (RLPC)[1]	**3,209**	**2,850**	**2,750**	**2,000**	MW
Credit for Load Resources (CLR)			**1,209**		MW
Current IFRO (OY 2018)	**-1,015**	**-858**	**-381**	**-179**	MW/0.1 Hz
First-Step target IFRO[1]	**-915**	**-1018**	**-380**	**-211**	MW/0.1 Hz
Second-Step target IFRO[1, 2]	**-815**				
Final target IFRO[1, 2]	**-787**				

Table 1: Interconnection Frequency Response Obligations (base year 2017)

IFRO = (RLPC – CLR)/Max Delta Freq/10

1. *These values are evaluated annually for changes in each Interconnection.*
2. *To reduce risk, the Eastern Interconnection IFRO will be stepped down annually from the 2017 value of -1,015 MW/0.1 Hz in -100 MW/0.1 Hz increments. If during the step down process, Interconnection Frequency Response Measure (FRM) declines by more than 10 percent, the ERO will halt the reduction in IFRO until such time that a determination can be made as to the cause of the degradation.*

Balancing Authority Frequency Response Obligation and Frequency Bias Setting

For a multiple Balancing Authority interconnection, the Interconnection FRO shown in Table 1 is allocated based on the Balancing Authority annual load and annual generation. The FRO allocation will be based on the following method:

$$\mathrm{FRO_{BA}} = \mathrm{IFRO} \quad \times \frac{\mathrm{Annual\ Gen_{BA}} + \mathrm{Annual\ Load_{BA}}}{\mathrm{Annual\ Gen_{Int}} + \mathrm{Annual\ Load_{Int}}}$$

Where:

- Annual Gen_{BA} is the total annual output of generating plants within the Balancing Authority Area (BAA).
- Annual $Load_{BA}$ is total annual Load within the BAA.
- Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that interconnection.
- Annual $Load_{Int}$ is the sum of all Annual $Load_{BA}$ values reported in that interconnection.

Balancing Authorities that elect to form a FRSG will calculate a FRSG FRO by adding together the individual BA FRO's.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Submit a joint Form 1 with the "FRSG" tab completed for the aggregate performance of the participating Balancing Authorities.

Balancing Authorities that merge or transfer load or generation are encouraged to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation to the Interconnection remains the same and so that CPS limits can be adjusted.

Each Balancing Authority reports its previous year's FRM, Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised Frequency Bias Settings on FRS Form 1. In addition, each Balancing Authority will report its two largest potential resource losses and any applicable N-2 RAS events in the form. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities will be given 30 days from the date the ERO posts the official list of events to submit their FRS Form 1.

Once the ERO reviews the data submitted in FRS Form 1 and FRS Form 2 for all Balancing Authorities, the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year:

- Frequency Bias Setting
- Frequency Response Obligation (FRO)

Once the data listed above is fully posted, the ERO will announce the three-day implementation period for changing the Frequency Bias Setting if it differs from that shown in the timeline below.

A Balancing Authority using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value):

- Any number the Balancing Authority chooses between 100 percent and 125 percent of its Frequency Response Measure as calculated on FRS Form 1
- Interconnection Minimum as determined by the ERO

For purposes of calculating the minimum Frequency Bias Setting, a Balancing Authority participating in a FRSG will need to calculate its stand-alone FRM using FRS Form 1 and FRS Form 2 to determine its minimum Frequency Bias Setting.

A Balancing Authority providing Overlap Regulation will report the historic peak demand and generation of its combined Balancing Authorities' areas on FRS Form 1 as described in Requirement R4.

Frequency Response Measure

The Balancing Authority will calculate its FRM from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event in a Balancing Authority area that is used to calculate its Frequency Response, expressed in MW/0.1Hz" as calculated on FRS Form 2 for each event shown on FRS Form 1. The events in FRS Form 1 are selected by the ERO using the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is the change in its Net Actual Interchange on its tie lines with adjacent Balancing Authorities divided by the change in Interconnection frequency. Some Balancing Authorities may choose to apply corrections to their Net Actual Interchange (NA_I) values to account for factors such as nonconforming loads. FRS Form 1 and 2 shows the types of adjustments that are allowed. Note that with the exception of the Contingent BA column, any adjustments made must be made for all events in an evaluation year.[1]

The ERO will use a standardized sampling interval of approximately 16 seconds before the event, up to the time of the event for the pre-event NA_I, and frequency (A values), and approximately 20 to 52 seconds after the event for the post-event NA_I (B values) in the computation of SEFRD values, dependent on the data scan rate of the Balancing Authority's Energy Management System (EMS).

All events listed on FRS Form 1 need to be included in the annual submission of FRS Forms 1 and 2. The only time a Balancing Authority should exclude an event is if its tie-line data or its Frequency data is corrupt, or its EMS was unavailable. FRS Form 2 has instructions on how to

[1] As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.

correct the BA's data if the given event is internal to the BA or if other authorized adjustments are used.

Assuming data entry is correct, FRS Form 1 will automatically calculate the Balancing Authority's FRM for the past 12 months as the median of the SEFRD values. A Balancing Authority electing to report as an FRSG or a provider of Overlap Regulation Service will provide an FRS Form 1 for the aggregate of its participants.

To allow Balancing Authorities to plan its operations, events with a "Point C" that cause the Interconnection Frequency to be lower than that shown in Table 1 above (for example, an event in the Eastern Interconnection that causes the Interconnection Frequency to go to 59.4 Hz) or higher than an equal change in frequency going above 60 Hz may be included in the list of events for that Interconnection. However, the calculation of the Balancing Authority response to such an event will be adjusted to show a frequency change only to the Target Minimum Frequency shown in Table 1 above (in the previous example this adjustment would cause Frequency to be shown as 59.5 Hz rather than 59.4 HZ) or a high frequency amount of an equal quantity. Should such an event happen, the ERO will provide additional guidance.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual Balancing Authority's Form 1s, with a summary spreadsheet that contains the sum of each participant's individual event performance.

Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities

Described below is the timeline for the exchange of information between the ERO and Balancing Authorities to:

- Facilitate the assignment of Balancing Authority FRO
- Calculate Balancing Authority FRM
- Determine Balancing Authority Frequency Bias Settings

Target Business Date	Activity
March 1	**FRS Form 1 is posted by the ERO* with all selected events for the operating year for BA usage.**
April 1	**BAs and FRSGs complete their frequency response forms for all four quarters, including the BAs' FBS calculations, returning the results to the ERO.**
May 1	**The ERO validates FBS values, computes the sum of all FBS values for each Interconnection.**
May 15	**The BAs not required to file FERC Form 714 receive a request to provide load and generation data as described in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard***** **to support FRO assignments and determining minimum FBS for the upcoming year. Data to be provided by July 15.**
June 1	The BA implements any changes to their FBS.
November 1	The ERO assigns FRO values and Minimum FBS for the upcoming year to the BAs.

* If 4th quarter posting of FRS Form 1s is delayed, the ERO may adjust the other timelines in this table by a similar amount.

** Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

Exhibit A2

Proposed Reliability Standard BAL-003-2
Redline

A. Introduction

1. **Title: Frequency Response and Frequency Bias Setting**

2. **Number: BAL-003-~~1.1~~2**

3. **Purpose:** To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.

4. **Applicability:**

   4.1. Functional Entities

   4.1.1. Balancing Authority

   4.1.1.1. ~~The~~ Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.

   4.1.2. Frequency Response Sharing Group

5. **Effective Date:** See Implementation Plan for BAL-003-2.

   ~~**5.1.** In those jurisdictions where regulatory approval is required, Requirements R2, R3 and R4 of this standard shall become effective the first calendar day of the first calendar quarter 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R2, R3 and R4 of this standard shall become effective the first calendar day of the first calendar quarter 12 months after Board of Trustees adoption.~~

   ~~**5.2.** In those jurisdictions where regulatory approval is required, Requirements R1 of this standard shall become effective the first calendar day of the first calendar quarter 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 of this standard shall become effective the first calendar day of the first calendar quarter 24 months after Board of Trustees adoption.~~

B. Requirements

R1. Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) 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. *[Risk Factor: High][Time Horizon: Real-time Operations]*

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 in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. *[Risk Factor: Medium][Time Horizon: Operations Planning]*

R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

3.1 Less than zero at all times, and

3.2 Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.

R4. 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 to either: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

- The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or
- The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.

Measures

M1. Each Frequency Response Sharing Group or Balancing Authority that is not a member of a Frequency Response Sharing Group shall have evidence such as dated data plus documented formula in either hardcopy or electronic format that it achieved an annual FRM (in accordance with the methods specified by the ERO in Attachment A with data from FRS Form 1 reported to the ERO as specified in Attachment A) that is equal to or more negative than its FRO to demonstrate compliance with Requirement R1.

M2. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service shall have evidence such as a dated document in hard copy or electronic format showing the ERO validated Frequency Bias Setting was implemented into its ACE calculation within the implementation period specified or other evidence to demonstrate compliance with Requirement R2.

M3. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and is utilizing variable Frequency Bias shall have evidence such as a dated report in hard copy or electronic format showing the average clock-minute average Frequency Bias Setting was less than zero and during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was equal to or more negative than its Frequency Response Obligation to demonstrate compliance with Requirement R3.

M4. The Balancing Authority shall have evidence such as a dated operating log, database or list in hard copy or electronic format showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation as specified in Requirement R4 to demonstrate compliance with Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

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

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If a Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.
- The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

- For Interconnections that are also Balancing Authorities, Tie Line Bias control and flat frequency control are equivalent and either is acceptable.

~~**1. Compliance Monitoring Process**~~

~~**1.1. Compliance Enforcement Authority**~~

~~The Regional Entity is the Compliance Enforcement Authority except where the responsible entity works for the Regional Entity. Where the responsible entity works for the Regional Entity, the Regional Entity will establish an agreement with the ERO or another entity approved by the ERO and FERC (i.e. another Regional Entity), to be responsible for compliance enforcement.~~

~~**1.2 Compliance Monitoring and Assessment Processes:**~~

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Investigation~~

~~Self-Reporting~~

~~Complaints~~

~~**1.3 Data Retention**~~

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

~~The Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.~~

~~The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.~~

~~If a Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.~~

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

~~**1.4 Additional Compliance Information**~~

~~For Interconnections that are also Balancing Authorities, Tie Line Bias control and flat frequency control are equivalent and either is acceptable.~~

2.0 Violation Severity Levels

R#	Lower VSL	Medium VSL	High VSL	Severe VSL
R1	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO ~~by more than 1% but~~ by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 30% or ~~by more than 15~~ 30 MW/0.1 Hz, whichever is the greater deviation from its FRO	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than ~~1~~30% but by at most ~~30~~45% but by at most 45% or ~~15~~45 MW/0.1 Hz, whichever one is the greater deviation from its FRO	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than ~~30~~45% or by more than ~~15~~45 MW/0.1 Hz, whichever is the greater deviation from its FRO
R2	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting failed to implement the validated Frequency Bias Setting value into its ACE calculation within the implementation period specified but did so within 5 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 5 calendar days but less than or equal to 15 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 15 calendar days but less than or equal to 25 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting did not implement the validated Frequency Bias Setting value into its ACE calculation in more than 25 calendar days from the implementation period specified by the ERO.
R3	The Balancing Authority that is a member of a multiple Balancing	The Balancing Authority that is a member of a multiple Balancing	The Balancing Authority that is a member of a multiple Balancing	The Balancing Authority that is a multiple Balancing Authority

	Authority Interconnection and is not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 1% but by at most 10%.	Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 10% but by at most 20%.	Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 20% but by at most 30%.	Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response obligation by more than 30%..
R4	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error less than or equal to 10% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 10% but less than or equal to 20% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 20% but less than or equal to 30% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 30% of the validated or calculated value. OR The Balancing Authority failed to change the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services.

D. Regional Variance

None

E. Associated Documents

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

FRS Form 1

FRS Form 2

Frequency Response Standard Background Document

~~Frequency Response Standard Background Document~~

F. Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	March 16, 2007	FERC Approval — Order 693	New
0a	December 19, 2007	Added Appendix 1 — Interpretation of R3 approved by BOT on October 23, 2007	Addition
0a	July 21, 2008	FERC Approval of Interpretation of R3	Addition
0b	February 12, 2008	Added Appendix 2 — Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition
0.1b	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial; updated version number to “0.1b”	Errata
0.1b	October 29, 2008	BOT approved errata changes	Errata
0.1a	May 13, 2009	FERC Approved errata changes – version changed to 0.1a (Interpretation of R2, R2.2, R5, and R5.1 not yet approved)	Errata

0.1b	May 21, 2009	FERC Approved Interpretation of R2, R2.2, R5, and R5.1	Addition
1	February 7, 2013	Adopted by NERC Board of Trustees	Complete Revision under Project 2007-12
1	January 16, 2014	FERC Order issued approving BAL-003-1. (Order becomes effective for R2, R3, and R4 April 1, 2015. R1 becomes effective April 1, 2016.)	
1	May 7, 2014	NERC Board of Trustees adopted revisions to VRF and VSLs in Requirement R1.	
1	November 26, 2014	FERC issued a letter order approved VRF and VSL revisions to Requirement R1.	
1.1	August 25, 2015	Added numbering to Introduction section, corrected parts numbering for R3, and adjusted font within section M4.	Errata
1.1	November 13, 2015	FERC Letter Order approved errata to BAL-003-1.1. Docket RD15-6-000	Errata
2	November 5, 2019	NERC Board of Trustees adopted BAL-003-2	New

Attachment A

BAL-003-2 Frequency Response & Frequency Bias Setting Standard

Supporting Document

Interconnection Frequency Response Obligation (IFRO)

The ERO, in consultation with regional representatives, has established a target ~~contingency protection~~reliability criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). Preliminary values are provided below. Certain values are assessed annually according to the methodology which is detailed in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.~~The default IFRO listed in Table 1 is based on the resource contingency criteria (RCC), which is the largest category C (N-2) event identified except for the Eastern Interconnection, which uses the largest event in the last 10 years. A maximum delta frequency (MDF) is calculated by adjusting a starting frequency for each Interconnection by the following:~~

- ~~Prevailing UFLS first step~~
- ~~CC_{Adj} which is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data~~
- ~~CB_R which is the statistically determined ratio of the Point C to Value B~~
- ~~BC'_{Adj} which is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.~~

~~The IFRO for each Interconnection in Table 1 is then calculated by dividing the RCC MWs by 10 times the MDF. In the Eastern Interconnection there is an additional adjustment (BC'_{Adj}) for the event nadir being below the Value B due to primary frequency response withdrawal. This IFRO includes uncertainty adjustments at a 95 % confidence level. Detailed descriptions of the calculations used in Table 1 below are defined in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.~~

Interconnection	**Eastern**	**Western**	**ERCOT**	**HQ**	Units
Max. Delta Frequency (MDF)	**0.420**	**0.280**	**0.405**	**0.947**	
Resource Loss Protection Criteria (RLPC)[1]	**3,209**	**2,850**	**2,750**	**2,000**	MW
Credit for Load Resources (CLR)			**1,209**		MW
Current IFRO (OY 2018)	**-1,015**	**-858**	**-381**	**-179**	MW/0.1 Hz
First-Step target IFRO[1]	**-915**	**-1018**	**-380**	**-211**	MW/0.1 Hz
Second-Step target IFRO[1, 2]	**-815**				
Final target IFRO[1, 2]	**-787**				

Table 1: Interconnection Frequency Response Obligations (base year 2017)

IFRO = (RLPC – CLR)/Max Delta Freq/10

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1. *These values are evaluated annually for changes in each Interconnection.*
2. *To reduce risk, the Eastern Interconnection IFRO will be stepped down annually from the 2017 value of -1,015 MW/0.1 Hz in -100 MW/0.1 Hz increments. If during the step down process, Interconnection Frequency Response Measure (FRM) declines by more than 10 percent, the ERO will halt the reduction in IFRO until such time that a determination can be made as to the cause of the degradation.*

~~Interconnection~~	~~Eastern~~	~~Western~~	~~ERCOT~~	~~HQ~~	~~Units~~
~~Starting Frequency (F_{Start})~~	~~59.974~~	~~59.976~~	~~59.963~~	~~59.972~~	~~Hz~~
~~Prevailing UFLS First Step~~	~~59.5*~~	~~59.5~~	~~59.3~~	~~58.5~~	~~Hz~~
~~Base Delta Frequency (DF_{Base})~~	~~0.474~~	~~0.476~~	~~0.663~~	~~1.472~~	~~Hz~~
~~CC_{ADJ}~~	~~0.007~~	~~0.004~~	~~0.012~~	~~N/A~~	~~Hz~~
~~Delta Frequency (DF_{CC})~~	~~0.467~~	~~0.472~~	~~0.651~~	~~1.472~~	~~Hz~~
~~CB_R~~	~~1.000~~	~~1.625~~	~~1.377~~	~~1.550~~	
~~Delta Frequency (DF_{CBR})~~	~~0.467~~	~~0.291~~	~~0.473~~	~~0.949~~	~~Hz~~
~~BC'_{ADJ}~~	~~0.018~~	~~N/A~~	~~N/A~~	~~N/A~~	~~Hz~~
~~Max. Delta Frequency (MDF)~~	~~0.449~~	~~0.291~~	~~0.473~~	~~0.949~~	
~~Resource Contingency Criteria (RCC)~~	~~4,500~~	~~2,740~~	~~2,750~~	~~1,700~~	~~MW~~
~~Credit for Load Resources (CLR)~~		~~300~~	~~1,400**~~		~~MW~~
~~IFRO~~	~~-1,002~~	~~-840~~	~~-286~~	~~-179~~	~~MW/0.1 Hz~~

~~**Table 1: Interconnection Frequency Response Obligations**~~

~~**The Eastern Interconnection UFLS set point listed is a compromise value set midway between the stable frequency minimum established in PRC-006-1 (59.3 Hz) and the local protection UFLS setting of 59.7 Hz used in Florida and Manitoba.*~~

~~***In the Base Obligation measure for ERCOT, 1400 MW (Load Resources triggered by Under Frequency Relays at 59.70 Hz) was reduced from its Resource Contingency Criteria level of 2750 MW to get 239 MW/0.1 Hz. This was reduced to accurately account for designed response from Load Resources within 30 cycles.*~~

~~An Interconnection may propose alternate IFRO protection criteria to the ERO by submitting a SAR with supporting technical documentation.~~

Balancing Authority Frequency Response Obligation ~~(FRO)~~ and Frequency Bias Setting

~~The ERO will manage the administrative procedure for annually assigning an FRO and implementation of the Frequency Bias Setting for each Balancing Authority. The annual timeline for all activities described in this section are shown below.~~

For a multiple Balancing Authority interconnection, the Interconnection FRO ~~Frequency Response Obligation~~ shown in Table 1 is allocated based on the Balancing Authority annual load and annual generation. The FRO allocation will be based on the following method:

$$FRO_{BA} = IFRO \quad \times \frac{\text{Annual Gen}_{BA} + \text{Annual Load}_{BA}}{\text{Annual Gen}_{Int} + \text{Annual Load}_{Int}}$$

Where:

- Annual Gen_{BA} is the total annual "Output of Generating Plants" within the Balancing Authority Area (BAA)~~, on FERC Form 714, column c of Part II - Schedule 3~~.
- Annual $Load_{BA}$ is total annual Load within the BAA~~, on FERC Form 714, column e of Part II - Schedule 3~~.
- Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that interconnection.
- Annual $Load_{Int}$ is the sum of all Annual $Load_{BA}$ values reported in that interconnection.

~~The data used for this calculation is from the most recently filed Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which utilized data from 2011.~~

~~Balancing Authorities that are not FERC jurisdictional should use the Form 714 Instructions to assemble and submit equivalent data to the ERO for use in the FRO Allocation process.~~

Balancing Authorities that elect to form a FRSG will calculate a FRSG FRO by adding together the individual BA FRO's.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- ~~Jointly s~~Submit a joint Form 1 with the "FRSG" tab completed for the aggregate performance of the participating Balancing Authorities~~the individual BAs' Form 1s, with a summary spreadsheet that contains the sum of each participant's individual event performance~~.

Balancing Authorities that merge or that transfer load or generation are encouraged to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation to the Interconnection remains the same and so that CPS limits can be adjusted.

Each Balancing Authority reports its previous year's ~~Frequency Response Measure (~~FRM~~)~~, Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised Frequency Bias Settings on FRS Form 1. In addition, each Balancing Authority will report its two largest potential resource losses and any applicable N-2 RAS events in the form. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities will be given 30 days from the date the ERO posts the official list of events to submit their FRS Form 1.

Once the ERO reviews the data submitted in FRS Form 1 and FRS Form 2 for all Balancing Authorities, the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year:

- Frequency Bias Setting
- Frequency Response Obligation (FRO)

Once the data listed above is fully posted, the ERO will announce the three-day implementation period for changing the Frequency Bias Setting if it differs from that shown in the timeline below.

A Balancing Authority ~~A~~ using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value):

- Any number the ~~BA~~ Balancing Authority chooses between 100~~%~~ percent and 125~~%~~ percent of its Frequency Response Measure as calculated on FRS Form 1
- Interconnection Minimum as determined by the ERO

For purposes of calculating the minimum Frequency Bias Setting, a Balancing Authority participating in a ~~Frequency Response Sharing Group~~FRSG will need to calculate its stand-alone ~~Frequency Response Measure~~FRM using FRS Form 1 and FRS Form 2 to determine its minimum Frequency Bias Setting.

A Balancing Authority providing Overlap Regulation will report the historic peak demand and generation of its combined ~~BAs'~~ Balancing Authorities' areas on FRS Form 1 as described in Requirement R4.

~~There are occasions when changes are needed to Bias Settings outside of the normal schedule. Examples are footprint changes between Balancing Authorities and major changes in load or generation or the formation of new Balancing Authorities. In such cases the changing Balancing Authorities will work with their Regions, NERC and the Resources Subcommittee to confirm appropriate changes to Bias Settings, FRO, CPS limits and Inadvertent Interchange balances.~~

~~If there is no net change to the Interconnection total Bias, the Balancing Authorities involved will agree on a date to implement their respective change in Bias Settings. The Balancing Authorities and ERO will also agree to the allocation of FRO such that the sum remains the same.~~

~~If there is a net change to the Interconnection total Bias, this will cause a change in CPS2 limits and FRO for other Balancing Authorities in the Interconnection. In this case, the ERO will notify the impacted Balancing Authorities of their respective changes and provide an implementation window for making the Bias Setting changes.~~

Frequency Response Measure ~~(FRM)~~

The Balancing Authority will calculate its FRM from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event from a Balancing Authority that is used to calculate its Frequency Response, expressed in MW/0.1Hz" as calculated on FRS Form 2 for each event shown on FRS Form 1. The events in FRS Form 1 are selected by the ERO using the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is basically the change in its Net Actual Interchange on its tie lines with its adjacent Balancing Authorities divided by the change in Interconnection frequency. ~~(~~Some Balancing Authorities may choose to apply corrections to their Net Actual Interchange (NA_I) values to account for factors such as nonconforming loads. FRS Form 1 and 2 shows the types of adjustments that are allowed. Note that with the exception of the Contingent BA column, any adjustments made must be made for all events in an evaluation year.[1] ~~As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-~~

[1] As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.

~~conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.)~~

The ERO will use a standardized sampling interval of approximately 16 seconds before the event up to the time of the event for the pre-event NA_I, and frequency (A values) and approximately 20 to 52 seconds after the event for the post-event NA_I (B values) in the computation of SEFRD values, dependent on the data scan rate of the Balancing Authority's Energy Management System (EMS).

All events listed on FRS Form 1 need to be included in the annual submission of FRS Forms 1 and 2. The only time a Balancing Authority should exclude an event is if its tie-line data or its Frequency data is corrupt or its EMS was unavailable. FRS Form 2 has instructions on how to correct the BA's data if the given event is internal to the BA or if other authorized adjustments are used.

Assuming data entry is correct, FRS Form 1 will automatically calculate the Balancing Authority's FRM for the past 12 months as the median of the SEFRD values. A Balancing Authority electing to report as an FRSG or a provider of Overlap Regulation Service will provide an FRS Form 1 for the aggregate of its participants.

To allow Balancing ~~authorities~~ Authorities to plan its operations, events with a "Point C" that cause the Interconnection Frequency to be lower than that shown in Table 1 above (for example, an event in the Eastern Interconnection that causes the Interconnection Frequency to go to 59.4 Hz) or higher than an equal change in frequency going above 60 Hz may be included in the list of events for that interconnection. However, the calculation of the ~~BA~~ Balancing Authority response to such an event will be adjusted to show a frequency change only to the Target Minimum Frequency shown in Table 1 above (in the previous example this adjustment would cause Frequency to be shown as 59.5 Hz rather than 59.4 HZ) or a high frequency amount of an equal quantity. Should such an event happen, the ERO will provide additional guidance.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or

Jointly submit the individual Balancing Authority's Form 1s, with a summary spreadsheet that contains the sum of each participant's individual event performance.

Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities

Described below is the timeline for the exchange of information between the ERO and Balancing Authorities ~~(BA)~~ to:

- Facilitate the assignment of ~~BA~~ Balancing Authority ~~Frequency Response Obligations (~~FRO~~)~~
- Calculate ~~BA~~ Balancing Authority ~~Frequency Response Measures (~~FRM~~)~~
- Determine ~~BA~~ Balancing Authority Frequency Bias Settings ~~(FBS)~~

Target Business Date	Activity
March 1	FRS Form 1 is posted by the ERO* with all selected events for the operating year for BA usage.

April 1	BAs and FRSGs complete their frequency response forms for all four quarters, including the BAs' FBS calculations, returning the results to the ERO.
May 1	The ERO validates FBS values, computes the sum of all FBS values for each Interconnection.
May 15	The BAs not required to file FERC Form 714 receive a request to provide load and generation data as described in the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard** to support FRO assignments and determining minimum FBS for the upcoming year. Data to be provided by July 15.
June 1	The BA implements any changes to their FBS.
November 1	The ERO assigns FRO values and Minimum FBS for the upcoming year to the BAs.

* If 4th quarter posting of FRS Form 1s is delayed, the ERO may adjust the other timelines in this table by a similar amount.

** Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

~~Target Date~~	~~Activity~~
~~April 30~~	~~The ERO reviews candidate frequency events and selects frequency events for the first quarter (December to February).~~
~~May 10~~	~~Form1 is posted with selected events from the first quarter for BA usage by the ERO.~~
~~May 15~~	~~The BAs receive a request to provide load and generation data as described in Attachment A to support FRO assignments and determining minimum FBS for BAs.~~
~~July 15~~	~~The BAs provide load and generation data as described in Attachment A to the ERO.~~
~~July 30~~	~~The ERO reviews candidate frequency events and selects frequency events for the second quarter (March to May).~~
~~August 10~~	~~Form1 is posted with selected events from the first and second quarters for BA usage by the ERO.~~
~~October 30~~	~~The ERO reviews candidate frequency events and selects frequency events for the third quarter (June to August)~~
~~November 10~~	~~Form1 is posted with selected events from the first, second, and third quarters for BA usage by the ERO.~~
~~November 20~~	~~If necessary, the ERO provides any updates to the necessary Frequency Response.~~
~~November 20~~	~~The ERO provides the fractional responsibility of each BA for the Interconnection's FRO and Minimum FBS to the BAs.~~

~~January 30~~	~~The ERO reviews candidate frequency events and selects frequency events for the fourth quarter (September to November).~~
~~2nd business day in February~~	~~Form1 is posted with all selected events for the year for BA usage by the ERO.~~
~~February 10~~	~~The ERO assigns FRO values to the BAs for the upcoming year.~~
~~March 7~~	~~BAs complete their frequency response sampling for all four quarters and their FBS calculation, returning the results to the ERO.~~
~~March 24~~	~~The ERO validates FBS values, computes the sum of all FBS values for each Interconnection, and determines L10 values for the CPS 2 criterion for each BA as applicable.~~
~~Any time during first 3 business days of April (unless specified otherwise by the ERO)~~	~~The BA implements any changes to their FBS and L10 value.~~

Exhibit B

Implementation Plan

Implementation Plan

Project 2017-01 Modifications to BAL-003-1.1
Reliability Standard BAL-003-2

Applicable Standard

- Standard BAL-003-2 — Frequency Response and Frequency Bias Setting

Requested Retirement(s)

- Standard BAL-003-1.1 — Frequency Response and Frequency Bias Setting

Applicable Entities

- Balancing Authority
  - o Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.
- Frequency Response Sharing Group

Background

The BAL-003-2 Phase I portion of the project revises the BAL-003-1.1 standard and process documents to address: (1) the inconsistencies in calculation of IFROs due to interconnection Frequency Response performance changes of Point C and/or Value B; (2) the Eastern Interconnection Resource Contingency Protection Criteria; (3) the frequency of nadir point limitations (currently limited to t0 to t+12); (4) clarification of language in Attachment A, i.e. related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities; and (5) enhancements to the BAL-003-1 FRS Forms that include the ability to collect and submit FRSG performance data. Additionally, the supporting procedural and process steps have been removed from Attachment A and captured in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.* This proposed document would be subject to approval by the North American Electric Reliability Corporation Operating Committee and Board of Trustees, and subject to informational filing with the Federal Energy Regulatory Commission, to facilitate timely process improvements as future lessons are learned.

Effective Date

BAL-003-2 — Frequency Response and Frequency Bias Setting
Where approval by an applicable governmental authority is required, the standard shall become effective on the first operating year (which begins on December 1st) that is 90 days after the

effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first operating year (which begins on December 1st) that is 90 days after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

BAL-003-1.1 — Frequency Response and Frequency Bias Setting
Reliability Standard BAL-003-1.1 shall be retired immediately prior to the effective date of BAL-003-2 in the particular jurisdiction in which the revised standard is becoming effective.

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Exhibit C

VRFs/VSLs Justification

Violation Risk Factor and Violation Severity Level Justifications

Project 2017-01 Modifications to BAL-003-1.1

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard BAL-003-2. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements. Please note, the SDT is only proposing to change the VSL for Requirement R1. As a result, justification is only provided for the VSL for Requirement R1.

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of a medium risk requirement is unlikely to lead to BES instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

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

FERC Guidelines for Violation Risk Factors

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

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

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

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

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

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

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

NERC Criteria for Violation Severity Levels

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

VSLs should be based on NERC's overarching criteria shown in the table below:

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

FERC Order of Violation Severity Levels

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

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

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

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

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

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

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

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

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

VRF Justification for BAL-003-1.1, Requirement R1

The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R1

This justification is provided on the following page.

VRF Justification for BAL-003-1.1, Requirement R2

The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R2

The VSL did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VRF Justification for BAL-003-1.1, Requirement R3

The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R3

The VSL did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VRF Justification for BAL-003-1.1, Requirement R4

The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R4

The VSL did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSLs for BAL-003-2, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority's (BA)s, or Frequency Response Sharing Group's (FRSG)s, Frequency Response Measure (FRM) was less negative than its Frequency Response Obligation (FRO) by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The BA's, or (FRSG)s, FRM was less negative than its FRO by more than 30% or 30 MW/0.1 Hz, whichever is the greater deviation from its FRO.	The BA's, or FRSGs, FRM was less negative than its FRO by more than 30% but by at most 45% or 45 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The BA's, or FRSG's, FRM was less negative than its FRO by more than 45% or by more than 45 MW/0.1 Hz, whichever is the greater deviation from its FRO.

VSL Justifications for BAL-003-2, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is not applicable since there was not a requirement mandating a certain level of Frequency Response prior to this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	Proposed VSL's are not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the amount the calculated FRM is less negative than FRO.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Proposed VSL's do not expand on what is required. The VSL's assigned only consider results of the calculation required. Proposed VSL's are consistent with the requirement.

VSL Justifications for BAL-003-2, Requirement R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

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Exhibit D

Order No. 672 Criteria

Exhibit D -- Order No. 672 Criteria

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

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

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

Proposed Reliability Standard BAL-003-2 provides requirements which are designed to ensure sufficient Frequency Response from Balancing Authorities to maintain Interconnection frequency within predefined boundaries by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. The standard is intended to provide consistent methods for determining the amount of Frequency Response needed in each Interconnection as well as measuring Frequency Response performance.

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1 *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards,* Order No. 672, 114 FERC ¶ 61,104, *order on reh'g*, Order No. 672-A, 114 FERC ¶ 61,328 (2006) ("Order No. 672").

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

Id. at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

Proposed Reliability Standard BAL-003-2 improves upon the current version of the standard through a set of targeted revisions to Attachment A to the standard. Corresponding revisions are also made to the supporting forms and *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. These revisions enhance the effectiveness of the standard by: (i) addressing issues related to frequency performance calculations in the currently effective standard, which could result in the Interconnection Frequency Response Obligation ("IFRO") values being increased year over year despite improved performance, or being decreased despite worsened performance; (ii) providing a repeatable and consistent method for determining the Interconnection Resource Contingency Criteria for all Interconnections; and (iii) clarifying language related to Frequency Response Reserve Sharing Groups and the timeline for Frequency Response and Frequency Bias Setting activities. These revisions are technically justified and provide a sound means of achieving the BAL-003 standard's goals of ensuring that sufficient Frequency Response is available to support Interconnection frequency.

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

The proposed Reliability Standard is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. The applicability of proposed Reliability Standard BAL-003-2 has not changed from the currently effective standard: it continues to remain applicable to Balancing Authorities and Frequency Response Sharing Groups. The proposed

[3] *Id*. at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

Id. at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

Reliability Standard clearly articulates the actions that such entities must take to comply with the standard.

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

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

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

The proposed Reliability Standard contains Measures that support each Requirement by clearly identifying what is required and how the Requirement will be enforced. These measures help provide clarity regarding how the Requirements will be enforced and help ensure that the

[4] *Id*. at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

[5] *Id*. at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

Requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

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

The proposed Reliability Standard achieves its reliability goals effectively and efficiently in accordance with Order No. 672. The proposed Reliability Standard clearly enumerates the responsibilities of applicable entities with respect to achieving an annual Frequency Response Measure equal to or more negative than its Frequency Response Obligation and implementing Frequency Bias Settings.

6. Proposed Reliability Standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[7]

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. To the contrary, the proposed Reliability Standard contains significant reliability benefits for the BPS and addresses issues identified by NERC in the 2016 Frequency Response Annual Analysis report.[8] The revisions would enhance the effectiveness of the proposed standard

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[6] *Id*. at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

[7] *Id*. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although FERC will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

Id. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

[8] *See* Petition at Section III.D.1.

and provided needed flexibility to address any future issues related to the calculation of Interconnection Frequency Response Obligation in a timely manner.

7. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[9]

The proposed Reliability Standard applies consistently throughout North America and does not favor one geographic area or regional model. The proposed standard would further this criterion by providing a method for determining the Resource Loss Protection Criteria that is consistent across all Interconnections.

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

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[10]

Proposed Reliability Standard BAL-003-2 has no undue negative effect on competition and does not unreasonably restrict the available transmission capacity or limit the use of the BPS in a preferential manner. The proposed standard requires the same performance by each of the applicable entities. The information sharing required by the proposed standard is necessary for reliability and can be accomplished without presenting any market or competition-related concerns.

9. The implementation time for the proposed Reliability Standard is reasonable.[11]

The proposed effective date for proposed Reliability Standard BAL-003-2 is just and reasonable and appropriately balances the urgency in the need to implement the standard while aligning its implementation with the existing BAL-003 timelines for calculation of IFRO values for the coming operating year. The proposed implementation plan is attached as **Exhibit B** to this Petition.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[12]

The proposed Reliability Standard was developed in accordance with NERC's Commission-approved, ANSI-accredited processes for developing and approving Reliability

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

[11] *Id*. at P 333. In considering whether a proposed Reliability Standard is just and reasonable, FERC will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

[12] *Id*. at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability

Standards. **Exhibit I** includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the proposed Reliability Standard. These processes included, among other things, comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the standard drafting team were properly noticed and open to the public.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[13]

NERC has identified no competing public interests regarding the request for approval of this proposed Reliability Standard. No comments were received that indicated the proposed Reliability Standard conflicts with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[14]

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

Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.

13 *Id*. at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

14 *Id*. at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

Exhibit E1

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

Clean

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Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

Version II - 2019

RELIABILITY | RESILIENCE | SECURITY

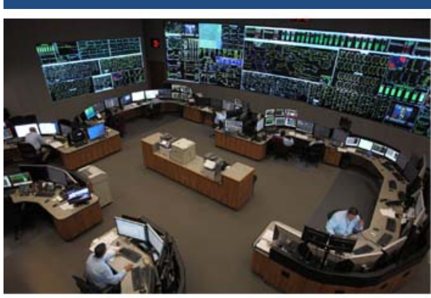


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Table of Contents

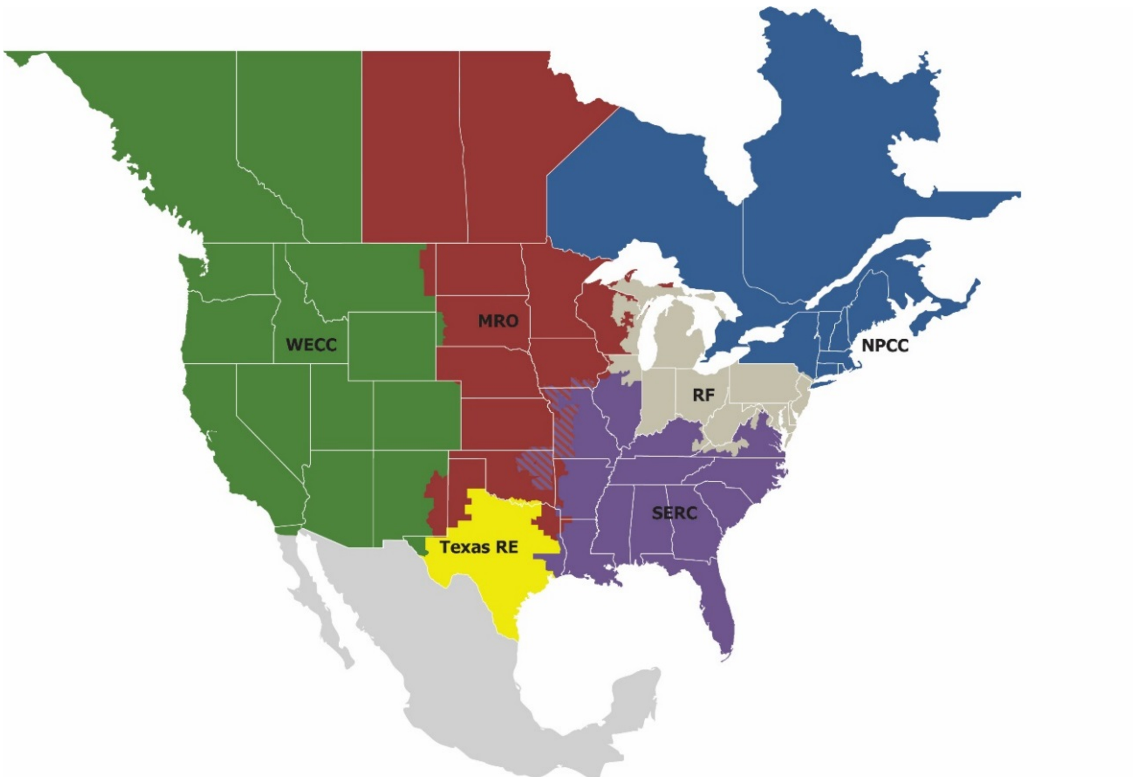
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

This procedure (Procedure) outlines the Electric Reliability Organization (ERO) process for supporting the Frequency Response Standard (FRS). A request for revisions may be submitted to the ERO or its designee for consideration. The request must provide a technical justification for the suggested modification. The ERO shall publicly post the suggested modification for a 45-day formal comment period and discuss the request in a public meeting. The ERO will make a recommendation to the NERC Board of Trustees (BOT), which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to this Procedure shall be filed with the Federal Energy Regulatory Commission (FERC) for informational purposes.

BAL-003-2 sets Interconnection Frequency Response Obligation (IFRO) to preset values subject to annual review. This procedure establishes the methods to be used for the annual review until Phase 2 of the SAR for Project 2017-01 has been addressed. If Frequency Response Measure (FRM) for the Eastern Interconnection degrades more than 10% in a year, the ERO will halt the reduction in IFRO until such time as a determination can be made as to the cause of the degradation.

Chapter 1: Event Selection Process

Event Selection Objectives

The goals of this procedure are to outline a transparent, repeatable process to annually identify a list of frequency events to be used to calculate Frequency Response to determine:

- Whether the Balancing Authority (BA) or Frequency Response Sharing Group (FRSG) met its Frequency Response Obligation, and
- An appropriate fixed Frequency Bias Setting.

Event Selection Criteria

1. The ERO will use the following criteria to select FRS excursion events for analysis. The events that best fit the criteria will be used to support the FRS. The evaluation period for performing the annual Frequency Bias Setting and the FRM calculation is December 1 of the prior year through November 30 of the current year.
2. The ERO will identify 20 to 35 frequency excursion events in each Interconnection for calculating the Frequency Bias Setting and the FRM. If the ERO cannot identify 20 frequency excursion events in a 12-month evaluation period satisfying the criteria below, then similar acceptable events from the previous year's evaluation period will be included with the data set by the ERO for determining compliance.
3. The ERO will use three criteria to determine if an acceptable frequency excursion event for the FRM has occurred:
    a. The change in frequency as defined by the difference from the A Value to Point C and the arrested frequency Point C exceeds the excursion threshold values specified for the Interconnection in Table 1 below.
        i. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline.
        ii. Point C is the arrested value of frequency observed within 20 seconds following the start of the excursion.

Table 1.1: Interconnection Frequency Excursion Threshold Values

Interconnection	A Value to Pt C	Point C (Low)	Point C (High)
East	0.04Hz	< 59.96	> 60.04
West	0.07Hz	< 59.95	> 60.05
ERCOT	0.08Hz	< 59.92	> 60.08
HQ	0.30Hz	< 59.85	> 60.15

    b. The time from the start of the rapid change in frequency until the point at which Frequency has stabilized within a narrow range should be less than 20 seconds.
    c. If any data point in the B Value average recovers to the A Value, the event will not be included.
4. Pre-disturbance frequency should be relatively steady and near 60.000 Hz for the A Value. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient

begins to decline. For example, given the choice of the two events below, the one on the right is preferred as the pre-disturbance frequency is stable and also closer to 60 Hz.

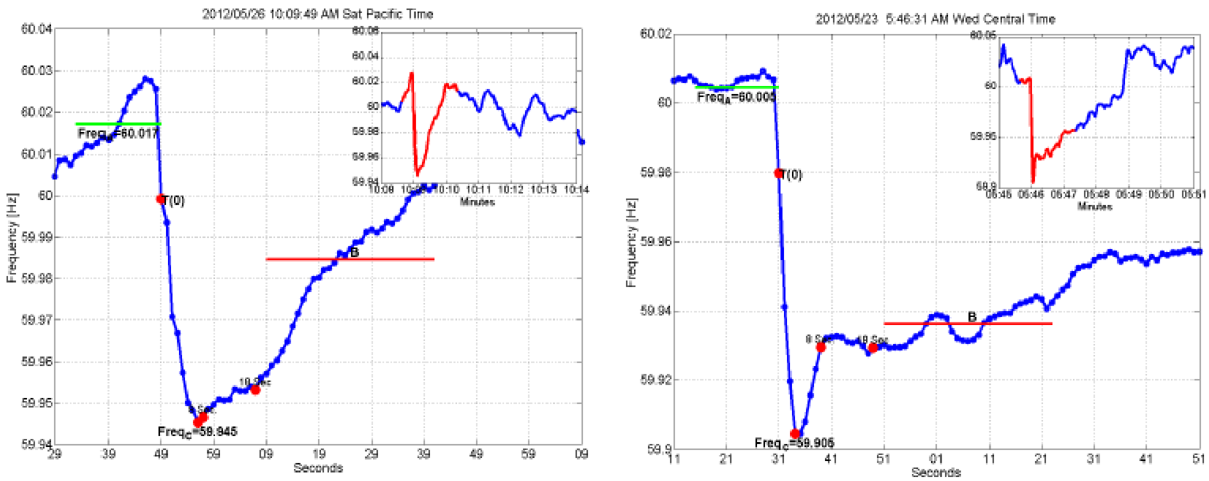


Figure 1.1: Pre-disturbance Frequency

5. Excursions that include 2 or more events that do not stabilize within 20 seconds will not be considered.
6. Frequency excursion events occurring during periods when large interchange schedule ramping or load change is happening, or within 5 minutes of the top of the hour may be excluded from consideration if other acceptable frequency excursion events from the same quarter are available.
7. The ERO will select the largest (A Value to Point C) 2 or 3 frequency excursion events occurring each month. If there are not 2 frequency excursion events satisfying the selection criteria in a month, then other frequency excursion events should be picked in the following sequence:
   a. From the same event quarter of the year.
   b. From an adjacent month.
   c. From a similar load season in the year (shoulder vs. summer/winter)
   d. The largest unused event.

As noted earlier, if a total of 20 events are not available in an evaluation year, then similar acceptable events from the next year's evaluation period will be included with the data set by the ERO for determining Frequency Response Obligation (FRO) compliance. The first year's small set of data will be reported and used for Bias Setting purposes, but compliance evaluation on the FRO will be done using a 24-month data set.

To assist Balancing Authority preparation for complying with this standard, the ERO will provide quarterly posting of candidate frequency excursion events for the current year FRM calculation. The ERO will post the final list of frequency excursion events used for standard compliance as specified in Attachment A of the standard. The following is a general description of the process that the ERO will use to ensure that BAs can evaluate events during the year in order to monitor their performance throughout the year.

Quarterly

The event lists will be reviewed quarterly, with the quarters defined as:

- December through February
- March through May
- June through August
- September through November

Based on criteria established in this Procedure, events will be selected to populate the FRS Form 1 for each Interconnection. The FRS Form 1's will be posted on the NERC website, in the Resources Subcommittee (RS) area under the title "Frequency Response Standard Resources". Updated FRS Form 1's will be posted at the end of each quarter listed above after a review by the NERC RS and its Frequency Working Group. While the events on this list are expected to be final, as outlined in the selection criteria, additional events may be considered, if the number of events throughout the year do not create a list of at least 20 events. It is intended that this quarterly posting of updates to the FRS Form 1 would allow BAs to evaluate the events throughout the year, lessening the burden when the yearly posting is made.

Annually

The final FRS Form 1 for each Interconnection, which would contain the events from all four quarters listed above, will be posted as specified in Attachment A. Each BA reports its previous year's Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO as specified in Attachment A using the final FRS Form 1. The ERO will check for errors and use the FRS Form 1 data to calculate CPS limits and FROs for the upcoming year.

Once the data listed above is fully reviewed, the ERO may adjust the implementation specified in Attachment A for changing the Frequency Bias Settings and CPS limits. This allows flexibility when each BA implements its settings.

Chapter 2: Process for Adjusting Interconnection Minimum Frequency Bias Setting

This procedure outlines the process the ERO is to use for modifying minimum Frequency Bias Settings to better meet reliability needs. The ERO will adjust the Frequency Bias Setting minimum in accordance with this procedure. The ERO will post the minimum Frequency Bias Setting values on the ERO website along with other balancing standard limits.

Under BAL-003-2, the minimum Frequency Bias Settings will be moved toward the natural Frequency Response in each Interconnection. In the first year, the minimum Frequency Bias Setting for each Interconnection is shown in Table 2 below. Each Interconnection Minimum Frequency Bias Setting is based on the sum of the non-coincident peak loads for each BA from the currently available FERC 714 Report or equivalent. This non-coincident peak load sum is multiplied by the percentage shown in Table 2 to get the Interconnection Minimum Frequency Bias Setting. The Interconnection Minimum Frequency Bias Setting is allocated among the BAs on an Interconnection using the same allocation method as is used for the allocation of the Frequency Response Obligation (FRO).

Table 2.1: Frequency Bias Setting Minimums

Interconnection	Interconnection Minimum Frequency Bias Setting (in MW/0.1Hz)
Eastern	0.9% of non-coincident peak load
Western	0.9% of non-coincident peak load
ERCOT	N/A
HQ	N/A

*The minimum Frequency Bias Setting requirement does not apply to a Balancing Authority that is the only Balancing Authority in its Interconnection. These Balancing Authorities are solely responsible for providing reliable frequency control of their Interconnection. These BAs are responsible for converting frequency error into a megawatt error to provide reliable frequency control, and the imposition of a minimum bias setting greater than the magnitude the Frequency Response Obligation may have the potential to cause control system hunting, and instability in the extreme.

The ERO, in coordination with the regions of each Interconnection, will annually review Frequency Bias Setting data submitted by BAs. 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 peak load (expressed in MW/0.1Hz), the minimum Frequency Bias Setting for BAs within that Interconnection may be reduced (in absolute value) in the subsequent years FRS Form 1 based on the technical evaluation and consultation with the regions affected by 0.1 percentage point of peak load (expressed in MW/0.1Hz) to better match that Frequency Bias Setting and natural Frequency Response.

The ERO, in coordination with the regions of each Interconnection, will monitor the impact of the reduction of minimum frequency bias settings, if any, on frequency performance, control performance, and system reliability. If unexpected and undesirable impacts such as, but not limited to, sluggish post-contingency restoration of frequency to schedule or control performance problems occur, then the prior reduction in the minimum frequency bias settings may be reversed, and/or the prospective reduction based on the criterion stated above may not be implemented.

Chapter 3: Interconnection Frequency Response Obligation Methodology

The Interconnection Resource Loss Protection Criteria (RLPC) is calculated based a resource loss in accordance with the following process:

NERC will request BAs to provide their two largest resource loss values and largest resource loss due to an N-1 or N-2 RAS event. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be needed to complete the calculation of the RLPC and IFRO.

BAs determine the two largest resource losses for the next operating year based on a review of the following items:

- The two largest independent Balancing Contingency Events, each due to a single contingency, identified using system models measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)
- The two largest units in the BA Area, regardless of shared ownership/responsibility.
- The two largest Remedial Action Scheme (RAS) resource losses (if any) which are initiated by single (N-1) contingency events.

The BA provides these two numbers determined above as Resource Loss A and Resource Loss B in the FR Form 1.

The BA should then provide the largest resource loss due to RAS operations (if any) which is initiated by a multiple contingency (N-2) event (RLPC cannot be lower than this value). If this RAS impacts more than a single BA, one BA is asked to take the lead and sum all resources lost due to the RAS event and provide that information.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.

The host BA (or planned host BA) where jointly-owned resources are physically located, should be the only BA to report that resource. The full ratings of the resource, not the fractional shares, should be reported.

Direct-current (DC) ties to asynchronous resources (such as DC ties between Interconnections, or the Manitoba Hydro Dorsey bi-pole ties to their northern asynchronous generation) should be considered as resource losses. DC lines such as the Pacific DC Intertie, which ties two sections of the same synchronous Interconnection together, should not be reported. A single pole block with normal clearing in a monopole or bi-pole high-voltage direct current system is a single contingency.

For a hypothetical four-BA Interconnection, Plant 1, in BA1, has two generators rated at 1200 MW each. Plant 2, in BA2 has a generator rated at 1400 MW. BA2's next largest contingency is 1000 MW. The two largest resource losses for BA3 and BA4 are listed below.

BA1	Resource Loss A = 1200 MW	Resource Loss B = 1200 MW	Both at Plant 1 (N-2)
BA2	Resource Loss A= 1400 MW	Resource Loss B = 1000 MW	Electrically separate
BA3	Resource Loss A = 1000 MW	Resource Loss B = 800 MW	Electrically separate
BA4	Resource Loss A = 1500 MW (DC TIE)	Resource Loss B = 500 MW	Electrically separate

The ERO would apply the RLPC selection methodology described above to determine the RLPC for the Interconnection. Using this methodology, results in the following:

Largest Resource Loss = 1500 MW Second Largest Resource Loss = 1400 MW Summation of two largest resource losses = 2900 MW Interconnection RLPC = 2900 MW

If only the N-2 Event was applied, the RLPC for the Interconnection would be 2400 MW. The summation of the two largest Interconnection Resource Losses will equal or exceed, but never fall short of, the N-2 Event scenario.

In order to evaluate RAS resource loss, single (N-1) and multiple (N-2) contingency events should be evaluated. Hypothetically, in an Interconnection:

BA1 RAS = 2850 MW	N-2 RAS event
BA1 Resource Loss A = 1150 MW	
BA1 Resource Loss B = 800 MW	
BA2 Resource Loss A = 1380 MW	
BA2 Resource Loss B = 1380 MW	
BA3 RAS = 1000 MW	N-1 RAS event
BA3 Resource Loss A = 800 MW	
BA3 Resource Loss B = 700 MW	

In this case, the ERO would determine the RLPC as follows: the summation of the two largest resource losses is 2760 MW. Since the N-2 RAS event exceeds the summation of the two largest single contingency events, the RLPC is the N-2 RAS event, or 2850 MW.

Interconnection RLPC Values

Based on initial review, the numbers below would be representative of the RLPC for each Interconnection.

<u>Eastern Interconnection:</u>
Present RLPC = 4500 MW   Load Credit = 0 MW
RESOURCE LOSS A = 1732 MW
RESOURCE LOSS B = 1477 MW
Proposed RLPC = 3209 MW

<u>Western Interconnection:</u>
Present RLPC = 2626 MW   Load Credit = 0 MW
RESOURCE LOSS A = 1505 MW
RESOURCE LOSS B = 1344 MW
N-2 RAS = 2850 MW
Proposed RLPC = 2850 MW

<u>ERCOT:</u>
Present RLPC = 2750 MW   Load Credit = 1209 MW
RESOURCE LOSS A = 1375 MW
RESOURCE LOSS B = 1375 MW
Proposed RLPC = 2750 MW

Quebec Interconnection:
Present RLPC = 1700 MW Load Credit = 0 MW
RESOURCE LOSS A = 1000 MW
RESOURCE LOSS B = 1000 MW
Proposed RLPC = 2000 MW

Calculation of IFRO Values

The IFRO is calculated using the RLPC (reference is from Table 1 from BAL-003-2):

$$\text{IFRO} = \frac{(\text{RLPC-CLR})}{(\text{MDF*10})} \quad \text{expressed as MW/0.1Hz}$$

MDF is the Maximum Delta Frequency for the specific interconnection as determined in the 2017 Frequency Response Annual Analysis (FRAA).

Interconnection Frequency Response Obligation

Interconnection	Eastern	Western	ERCOT	HQ	Units
Max. Delta Frequency (MDF)	**0.420**	**0.280**	**0.405**	**0.947**	Hz
Resource Loss Protection Criteria (RLPC)	**3,209**	**2,850**	**2,750**	**2,000**	MW
Credit for Load Resources (CLR)			**1,209**		MW
Calculated IFRO	**-787***	**-1018**	**-380**	**-211**	MW/0.1Hz

* Eastern Interconnection IFRO will be stepped down to this level over three years per BAL-003-2.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Exhibit E2

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard
Redline

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

Version II - 2019

RELIABILITY | RESILIENCE | SECURITY

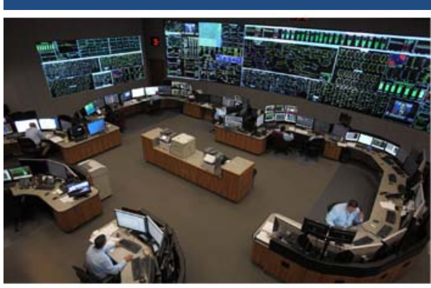



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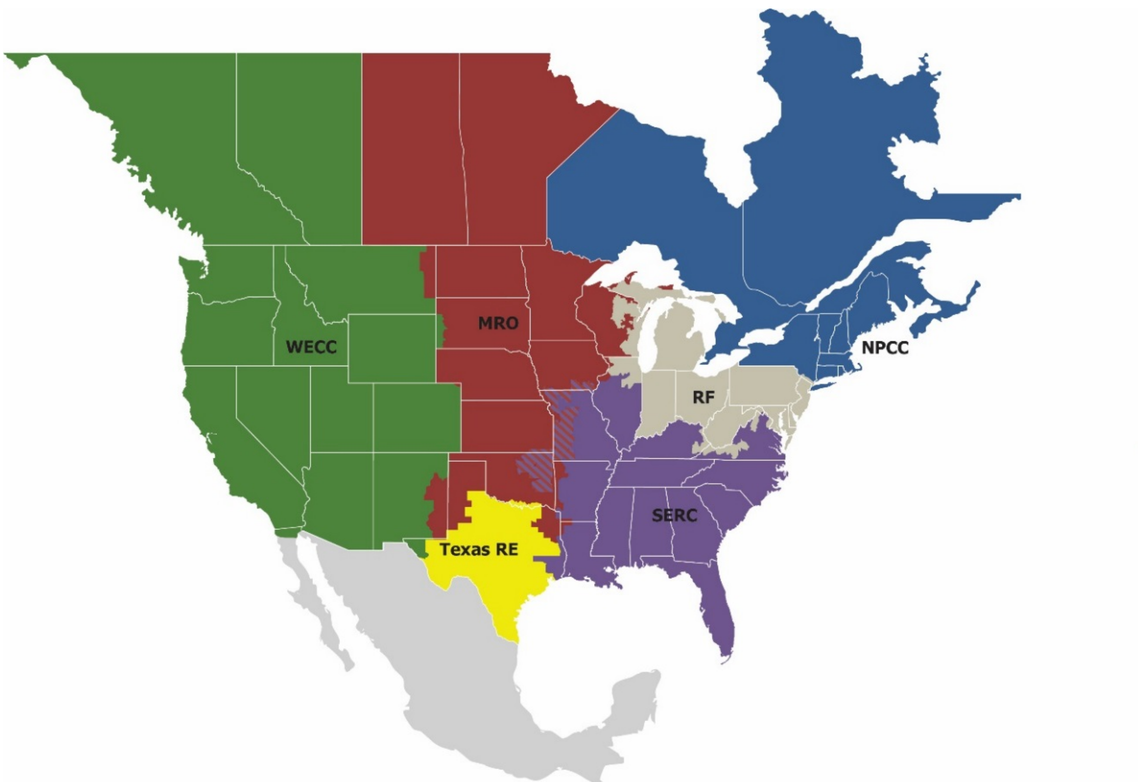
Table of Contents

Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

This procedure outlines the Electric Reliability Organization (ERO) process for supporting the Frequency Response Standard (FRS). A ~~Procedure revision~~ request for revisions may be submitted to the ERO or its designee for consideration. The ~~revision~~ request must provide a technical justification for the suggested modification. The ERO shall publicly post the suggested modification for a 45-day formal comment period and discuss the ~~revision~~ request in a public meeting. The ERO will make a recommendation to the NERC Board of Trustees (BOT), which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to this Procedure shall be filed with the Federal Energy Regulatory Commission (FERC) for informational purposes.

BAL-003-2 sets Interconnection Frequency Response Obligation (IFRO) to preset values subject to annual review. This procedure establishes the methods to be used for the annual review until Phase 2 of the SAR for Project 2017-01 has been addressed. If Frequency Response Measure (FRM) for the Eastern Interconnection degrades more than 10% in a year, the ERO will halt the reduction in IFRO until such time as a determination can be made as to the cause of the degradation.

Chapter 1: Event Selection Process

Event Selection Objectives

The goals of this procedure are to outline a transparent, repeatable process to annually identify a list of frequency events to be used ~~by Balancing Authorities (BA)~~ to calculate their Frequency Response to determine:

- Whether the ~~BA~~ Balancing Authority or Frequency Response Sharing Group (FRSG) met its Frequency Response Obligation, and
- An appropriate fixed Frequency Bias Setting.

Event Selection Criteria

1. The ERO will use the following criteria to select FRS ~~frequency~~ excursion events for analysis. The events that best fit the criteria will be used to support the FRS. ~~-~~The evaluation period for performing the annual Frequency Bias Setting and the ~~Frequency Response Measure (FRM)~~FRM calculation is December 1 of the prior year through November 30 of the current year.
2. The ERO will identify 20 to 35 frequency excursion events in each Interconnection for calculating the Frequency Bias Setting and the FRM. ~~-~~If the ERO cannot identify 20 frequency excursion events in a 12 month evaluation period satisfying the criteria below, then similar acceptable events from the ~~subsequent~~ previous year's evaluation period will be included with the data set by the ERO for determining ~~FRS~~ compliance. ~~This is described later.~~
3. The ERO will use three criteria to determine if an acceptable frequency excursion event for the FRM has occurred:
   a. The change in frequency as defined by the difference from the A Value to Point C and the arrested frequency Point C exceeds the excursion threshold values specified for the Interconnection in Table 1 below.
      i. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline.
      ii. Point C is the arrested value of frequency observed within ~~12~~ 20 seconds following the start of the excursion.

Table 1.1: Interconnection Frequency Excursion Threshold Values

Interconnection	A Value to Pt C	Point C (Low)	Point C (High)
East	0.04Hz	< 59.96	> 60.04
West	0.07Hz	< 59.95	> 60.05
ERCOT	0.~~15Hz~~08Hz	< 59.~~90~~92	> 60.~~10~~08
HQ	0.30Hz	< 59.85	> 60.15

   b. The time from the start of the rapid change in frequency until the point at which Frequency has stabilized within a narrow range should be less than ~~18~~ 20 seconds.
   c. If any data point in the B Value average recovers to the A Value, the event will not be included.

4. Pre-disturbance frequency should be relatively steady and near 60.000 Hz for the A Value. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline. For example, given the choice of the two events below, the one on the right is preferred as the pre-disturbance frequency is stable and also closer to 60 Hz.

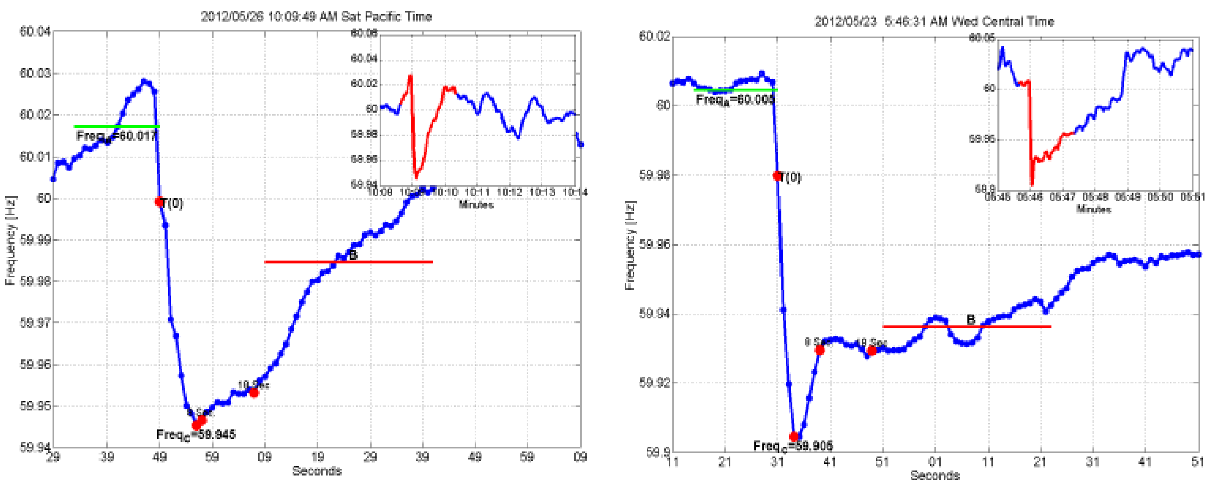


Figure 1.1: Pre-disturbance Frequency

5. Excursions that include 2 or more events that do not stabilize within ~~18~~ 20 seconds will not be considered.
6. Frequency excursion events occurring during periods~~:~~ when large interchange schedule ramping or load change is happening, or within 5 minutes of the top of the hour may be excluded from consideration if other acceptable frequency excursion events from the same quarter are available.

   ~~a. when large interchange schedule ramping or load change is happening, or~~

   ~~b. within 5 minutes of the top of the hour, will be excluded from consideration if other acceptable frequency excursion events from the same quarter are available.~~
7. The ERO will select the largest (A Value to Point C) 2 or 3 frequency excursion events occurring each month. If there are not 2 frequency excursion events satisfying the selection criteria in a month, then other frequency excursion events should be picked in the following sequence:
   a. From the same event quarter of the year.
   b. From an adjacent month.
   c. From a similar load season in the year (shoulder vs. summer/winter)
   d. The largest unused event.

As noted earlier, if a total of 20 events are not available in an evaluation year, then similar acceptable events from the next year's evaluation period will be included with the data set by the ERO for determining Frequency Response Obligation (FRO) compliance. The first year's small set of data will be reported and used for Bias Setting purposes, but compliance evaluation on the FRO will be done using a 24-month data set.

To assist Balancing Authority preparation for complying with this standard, the ERO will provide quarterly posting of candidate frequency excursion events for the current year FRM calculation. The ERO will post the final list of frequency excursion events used for standard compliance as specified in Attachment A of ~~BAL-003-1~~the standard. The following is a general description of the process that the ERO will use to ensure that BAs can evaluate events during the year in order to monitor their performance throughout the year.

~~Monthly~~

~~Candidate events will be initially screened by the "Frequency Event Detection Methodology" shown on the following link located on the NERC Resources Subcommittee area of the NERC website: http://www.nerc.com/docs/oc/rs/Frequency_Event_Detection_Methodology_and_Criteria_Oct_2011.pdf. Each month's list will be posted by the end of the following month on the NERC website, http://www.nerc.com/filez/rs.html and listed under "Candidate Frequency Events".~~

Quarterly

The ~~monthly~~ event lists will be reviewed quarterly, with the quarters defined as:

- December through February
- March through May
- June through August
- September through November

Based on criteria established in this Procedure~~the "*Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*"~~, events will be selected to populate the FRS Form 1 for each Interconnection. The FRS Form 1's will be posted on the NERC website, in the Resources Subcommittee (RS) area under the title "Frequency Response Standard Resources". Updated FRS Form 1's will be posted at the end of each quarter listed above after a review by the NERC RS'~~-~~ and Frequency Working Group. While the events on this list are expected to be final, as outlined in the selection criteria, additional events may be considered, if the number of events throughout the year do not create a list of at least 20 events. It is intended that this quarterly posting of updates to the FRS Form 1 would allow BAs to evaluate the events throughout the year, lessening the burden when the yearly posting is made.

Annually

The final FRS Form 1 for each Interconnection, which would contain the events from all four quarters listed above, will be posted as specified in Attachment A. Each ~~Balancing Authority~~BA reports its previous year's Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO as specified in Attachment A using the final FRS Form 1. The ERO will check for errors and use the FRS Form 1 data to calculate CPS limits and FROs for the upcoming year.

Once the data listed above is fully reviewed, the ERO may adjust the implementation specified in Attachment A for changing the Frequency Bias Settings and CPS limits. This allows flexibility in when each BA implements its settings.

Chapter 2: Process for Adjusting Interconnection Minimum Frequency Bias Setting

This procedure outlines the process the ERO is to use for modifying minimum Frequency Bias Settings to better meet reliability needs. The ERO will adjust the Frequency Bias Setting minimum in accordance with this procedure. The ERO will post the minimum Frequency Bias Setting values on the ERO website along with other balancing standard limits.

Under BAL-003-~~1~~2, the minimum Frequency Bias Settings will be moved toward the natural Frequency Response in each ~~interconnection~~Interconnection. In the first year, the minimum Frequency Bias Setting for each ~~interconnection~~ Interconnection is shown in Table 2 below. Each Interconnection Minimum Frequency Bias Setting is based on the sum of the non-coincident peak loads for each BA from the currently available FERC 714 Report or equivalent. This non-coincident peak load sum is multiplied by the percentage shown in Table 2 to get the Interconnection Minimum Frequency Bias Setting. The Interconnection Minimum Frequency Bias Setting is allocated among the BAs on an ~~interconnection~~ Interconnection using the same allocation method as is used for the allocation of the Frequency Response Obligation (FRO).

Table 2.1: Frequency Bias Setting Minimums

Interconnection	Interconnection Minimum Frequency Bias Setting (in MW/0.1Hz)
Eastern	0.9% of non-coincident peak load
Western	0.9% of non-coincident peak load
ERCOT	N/A
HQ	N/A

*The minimum Frequency Bias Setting requirement does not apply to a Balancing Authority that is the only Balancing Authority in its Interconnection. These Balancing Authorities are solely responsible for providing reliable frequency control of their Interconnection. These ~~Balancing Authorities~~BAs are responsible for converting frequency error into a megawatt error to provide reliable frequency control, and the imposition of a minimum bias setting greater than the magnitude the Frequency Response Obligation may have the potential to cause control system hunting, and instability in the extreme.

The ERO, in coordination with the regions of each interconnection, will annually review Frequency Bias Setting data submitted by BAs. 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 peak load (expressed in MW/0.1Hz), the minimum Frequency Bias Setting for BAs within that Interconnection may be reduced (in absolute value) in the subsequent years FRS Form 1 based on the technical evaluation and consultation with the regions affected by 0.1 percentage point of peak load (expressed in MW/0.1Hz) to better match that Frequency Bias Setting and natural Frequency Response.

The ERO, in coordination with the regions of each Interconnection, will monitor the impact of the reduction of minimum frequency bias settings, if any, on frequency performance, control performance, and system reliability. If unexpected and undesirable impacts such as, but not limited to, sluggish post-contingency restoration of frequency to schedule or control performance problems occur, then the prior reduction in the minimum frequency bias settings may be reversed, and/or the prospective reduction based on the criterion stated above may not be implemented.

Chapter 3: Interconnection Frequency Response Obligation Methodology

The Interconnection Resource Loss Protection Criteria (RLPC) is calculated based a resource loss in accordance with the following process:

NERC will request BAs to provide their two largest resource loss values and largest resource loss due to an N-1 or N-2 RAS event. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be needed to complete the calculation of the RLPC and IFRO.

BAs determine the two largest resource losses for the next operating year based on a review of the following items:

- The two largest independent Balancing Contingency Events, each due to a single contingency, identified using system models measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)
- The two largest units in the BA Area, regardless of shared ownership/responsibility.
- The two largest Remedial Action Scheme (RAS) resource losses (if any) which are initiated by single (N-1) contingency events.

The BA provides these two numbers determined above as Resource Loss A and Resource Loss B in the FR Form 1.

The BA should then provide the largest resource loss due to RAS operations (if any) which is initiated by a multiple contingency (N-2) event (RLPC cannot be lower than this value). If this RAS impacts more than a single BA, one BA is asked to take the lead and sum all resources lost due to the RAS event and provide that information.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.

The host BA (or planned host BA) where jointly-owned resources are physically located, should be the only BA to report that resource. The full ratings of the resource, not the fractional shares, should be reported.

Direct-current (DC) ties to asynchronous resources (such as DC ties between Interconnections, or the Manitoba Hydro Dorsey bi-pole ties to their northern asynchronous generation) should be considered as resource losses. DC lines such as the Pacific DC Intertie, which ties two sections of the same synchronous Interconnection together, should not be reported. A single pole block with normal clearing in a monopole or bi-pole high-voltage direct current system is a single contingency.

For a hypothetical four-BA Interconnection, Plant 1, in BA1, has two generators rated at 1200 MW each. Plant 2, in BA2 has a generator rated at 1400 MW. BA2's next largest contingency is 1000 MW. The two largest resource losses for BA3 and BA4 are listed below.

BA1	Resource Loss A = 1200 MW	Resource Loss B = 1200 MW	Both at Plant 1 (N-2)
BA2	Resource Loss A= 1400 MW	Resource Loss B = 1000 MW	Electrically separate
BA3	Resource Loss A = 1000 MW	Resource Loss B = 800 MW	Electrically separate
BA4	Resource Loss A = 1500 MW (DC TIE)	Resource Loss B = 500 MW	Electrically separate

The ERO would apply the RLPC selection methodology described above to determine the RLPC for the Interconnection. Using this methodology, results in the following:

Largest Resource Loss = 1500 MW Second Largest Resource Loss = 1400 MW Summation of two largest resource losses = 2900 MW Interconnection RLPC = 2900 MW

If only the N-2 Event was applied, the RLPC for the Interconnection would be 2400 MW. The summation of the two largest Interconnection Resource Losses will equal or exceed, but never fall short of, the N-2 Event scenario.

In order to evaluate RAS resource loss, single (N-1) and multiple (N-2) contingency events should be evaluated. Hypothetically, in an Interconnection:

BA1 RAS = 2850 MW	N-2 RAS event
BA1 Resource Loss A = 1150 MW	
BA1 Resource Loss B = 800 MW	
BA2 Resource Loss A = 1380 MW	
BA2 Resource Loss B = 1380 MW	
BA3 RAS = 1000 MW	N-1 RAS event
BA3 Resource Loss A = 800 MW	
BA3 Resource Loss B = 700 MW	

In this case, the ERO would determine the RLPC as follows: the summation of the two largest resource losses is 2760 MW. Since the N-2 RAS event exceeds the summation of the two largest single contingency events, the RLPC is the N-2 RAS event, or 2850 MW.

Interconnection RLPC Values

Based on initial review, the numbers below would be representative of the RLPC for each Interconnection.

Eastern Interconnection:
Present RLPC = 4500 MW Load Credit = 0 MW
RESOURCE LOSS A = 1732 MW
RESOURCE LOSS B = 1477 MW
Proposed RLPC = 3209 MW

Western Interconnection:
Present RLPC = 2626 MW Load Credit = 0 MW
RESOURCE LOSS A = 1505 MW
RESOURCE LOSS B = 1344 MW
N-2 RAS = 2850 MW
Proposed RLPC = 2850 MW

ERCOT:
Present RLPC = 2750 MW Load Credit = 1209 MW
RESOURCE LOSS A = 1375 MW
RESOURCE LOSS B = 1375 MW
Proposed RLPC = 2750 MW

Quebec Interconnection:
Present RLPC = 1700 MW Load Credit = 0 MW
RESOURCE LOSS A = 1000 MW
RESOURCE LOSS B = 1000 MW
Proposed RLPC = 2000 MW

Calculation of IFRO Values

The IFRO is calculated using the RLPC (reference is from Table 1 from BAL-003-2):

IFRO = (RLPC-CLR) expressed as MW/0.1Hz
(MDF*10)

MDF is the Maximum Delta Frequency for the specific interconnection as determined in the 2017 Frequency Response Annual Analysis (FRAA).

Interconnection Frequency Response Obligation

Interconnection	Eastern	Western	ERCOT	HQ	Units
Max. Delta Frequency (MDF)	**0.420**	**0.280**	**0.405**	**0.947**	Hz
Resource Loss Protection Criteria (RLPC)	**3,209**	**2,850**	**2,750**	**2,000**	MW
Credit for Load Resources (CLR)			**1,209**		MW
Calculated IFRO	**-787***	**-1018**	**-380**	**-211**	MW/0.1Hz

* Eastern Interconnection IFRO will be stepped down to this level over three years per BAL-003-2.

~~This procedure outlines the process the ERO is to use for determining the Interconnection Frequency Response Obligation (IFRO).~~

~~The following are the formulae that comprise the calculation of the IFROs.~~

$$\cancel{DF_{Base} = F_{Start} - UFLS}$$
$$\cancel{DF_{CC} = DF_{Base} - CC_{Adj}}$$
$$\cancel{DF_{CBR} = \frac{DF_{CC}}{CB_R}}$$
$$\cancel{MDF = DF_{CBR} - BC'_{Adj}}$$
$$\cancel{ARCC = RCC - CLR}$$
$$\cancel{IFRO = \frac{ARCC}{10 * MDF}}$$

~~Where:~~
~~DF_{Base} is the base delta frequency.~~
~~FStart is the starting frequency determined by the statistical analysis.~~
~~UFLS is the highest UFLS trip setpoint for the interconnection.~~
~~CCAdj is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data.~~
~~DFCC is the delta frequency adjusted for the differences between 1-second and sub-second Point C observations for frequency events.~~
~~CBR is the statistically determined ratio of the Point C to Value B.~~

~~DFCBR is the delta frequency adjusted for the ratio of the Point C to Value B.~~

~~BC'ADJ is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.~~

~~MDF is the maximum allowable delta frequency.~~

~~RCC is the resource contingency criteria.~~

~~CLR is the credit for load resources.~~

~~ARCC is the adjusted resource contingency criteria adjusted for the credit for load resources.~~

~~IFRO is the interconnection frequency response obligation.~~

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Exhibit F

NERC Staff Report

Interconnection Frequency Response Obligation Determination and Validation:
BAL-003-2 SDT Revised RLPC and IFRO Method

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interconnection Frequency Response Obligation Determination and Validation

BAL-003-2 SDT Revised RLPC and IFRO Method

November 2019

RELIABILITY | RESILIENCE | SECURITY




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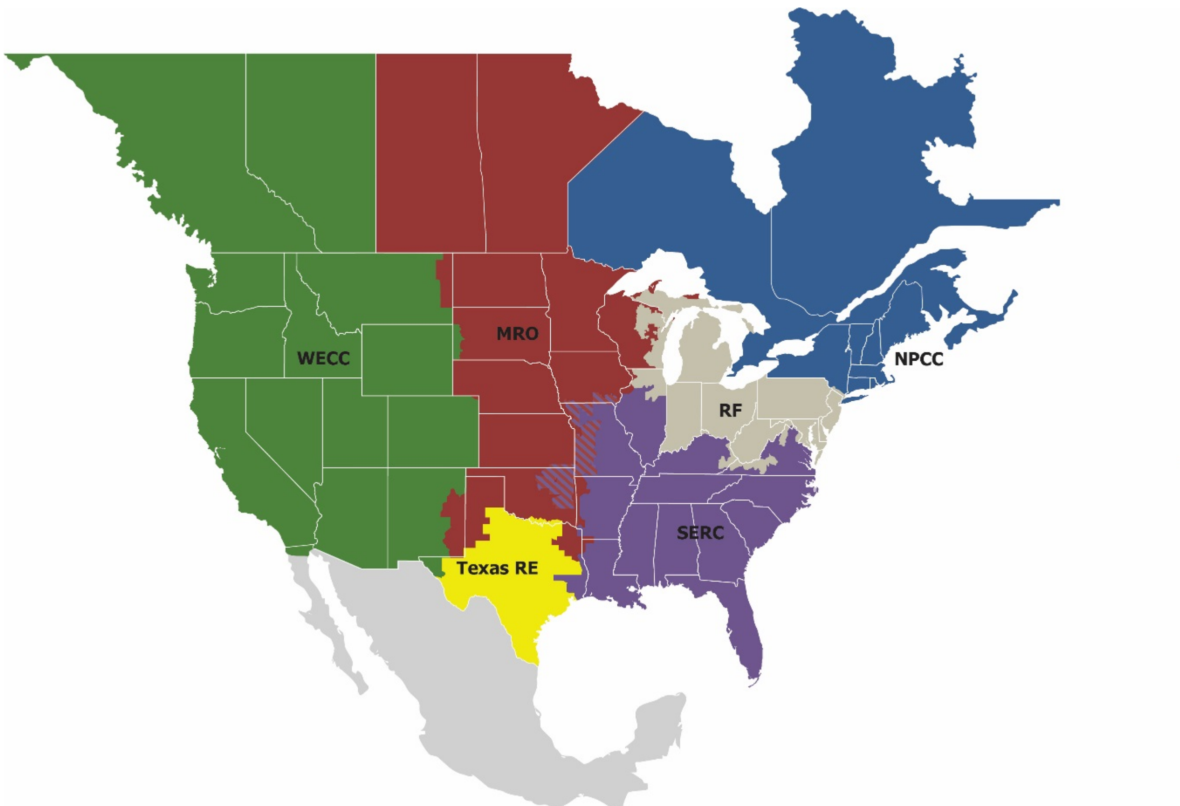
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Executive Summary

The BAL-003-2 Standard Drafting Team (SDT) has proposed revisions to *Reliability Standard BAL-003-1.1 – Frequency Response and Frequency Bias Setting*[1] that would modify how the Interconnection Frequency Response Obligation (IFRO) will be determined. This report describes the proposed changes to the method of determining the resource loss protection criteria (RLPC) and shows how those proposed changes would be reflected in the IFROs. This report also documents how the proposed changes in IFROs were validated by NERC staff using dynamic simulations to assure that those levels of response are adequate to protect the respective Interconnection. The processes and analysis methods for the proposed changes and their validation are documented herein.

Eastern Interconnection

The BAL-003-2 SDT recommended a reduction in the Eastern Interconnection (EI) RLPC from 4,500 MW to 3,209 MW with the resulting IFRO phased in over three increments following annual evaluation of each previous reduction. The initial reduction in IFRO would be from the current 1,015 MW to 915 MW/0.1 Hz followed by subsequent reductions to 815 and 764 MW/0.1 Hz. The 4,500 MW value was recommended in the *2012 Frequency Response Initiative Report*[2] and was the largest resource contingency event in the previous ten years at the time of the report.

The August 2007 event that led to the initial EI RLPC involved nine generators across three states, resulted in a loss of 4,457 MW, and a frequency nadir of 59.863 Hz. The subsequent NERC *Event Analysis Report* identified root causes and major contributory factors in addition to entity-specific and industry-wide recommendations to improve reliability. As a result of the event, the Regional Entity initiated a compliance violation investigation (CVI) that led to an entity settlement agreement to resolve alleged violations of requirements in four NERC Reliability Standards and a mitigation plan that was completed on June 30, 2010. Since the recommendations set forth in the *2012 Frequency Response Initiative Report* the largest resource loss event in the EI has been 2,344 MW in April 2013.

The 3,209 MW value was determined by the SDT and is the sum of the two largest single contingencies (N-1) in the EI at the time of their review as shown in **Appendix B**. Dynamic simulations successfully validated an EI IFRO as low as 787 MW/0.1 Hz with a resulting minimum Point C frequency nadir of 59.511 Hz.

Western Interconnection

The BAL-003-2 SDT recommended an increase in the Western Interconnection (WI) RLPC from 2,626 MW to 2,850 MW with the resulting IFRO increasing from 858 to 1,018 MW/0.1 Hz.

The 2,850 MW value was determined by the SDT and is the remedial action scheme (RAS) resource loss, which is initiated by multiple (N-2) contingency events and is larger than the sum of the two largest single contingencies (N-1) in the WI at the time of the SDT review as shown in **Appendix B**. Dynamic simulations successfully validated a WI IFRO as low as 1,013 MW/0.1 Hz with a resulting minimum Point C frequency nadir of 59.534 Hz.

Texas Interconnection

The BAL-003-2 SDT recommended no change in the Texas Interconnection (TI) RLPC of 2,750 MW with the IFRO decreasing slightly from 381 to 380 MW/0.1 Hz.

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The 2,750 MW value was determined by the SDT and is the sum of the two largest single contingencies (N-1) in the TI at the time of their review as shown in **Appendix B**. Dynamic simulations successfully validated a TI IFRO as low as 378 MW/0.1 Hz with a resulting minimum Point C frequency nadir of 59.302 Hz.

[1] http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-1.1.pdf

[2] https://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

Introduction

This document describes the proposed changes to the method of determining the RLPCs and shows how those proposed changes would be reflected in the IFROs and how those revised IFROs would be tested using dynamic simulation to assure that those levels of response are adequate to protect the Interconnection. The processes and analysis methods for the proposed changes and their validation are documented herein.

Background

Frequency support is recognized as an essential reliability service. The NERC *Reliability Standard BAL-003-1.1* is intended to require sufficient frequency response from the Balancing Authorities (BAs) to maintain Interconnection frequency within predefined boundaries by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. *Reliability Standard BAL-003-1.1* is intended to provide consistent methods for determining the amount of frequency response needed in each Interconnection as well as measuring frequency response performance. The standard applies to all BAs or the Frequency Response Sharing Group (FRSG) if the BA is a member of an FRSG.

The RLPC is the respective Interconnection design resource loss in MW; it is used to determine the IFRO. An "N-2" event is defined as a single initiating event that leads to multiple electrical facilities being removed from service. Examples of this are breaker failure events, bus faults, or double-circuit tower outages.

Previously, the RLPC has been calculated from the largest N-2 events identified in each Interconnection except for the EI. In the EI, the RLPC has been calculated using the largest single event in the previous ten years.

The RLPC value should be set for each Interconnection such that the under frequency load shedding (UFLS) safety net is not activated for the largest N-2 event. The previous BAL-003 IFRO method determined that the largest N-2 event should not precipitate an UFLS event. The original basis for determining the RLPCs and IFROs was prescribed in the *2012 Frequency Response Initiative Report*[3] and annually updated in the *Frequency Response Annual Analysis* reports.[4]

The BAL-003-2 SDT is proposing revisions to *Reliability Standard BAL-003-1.1 – Frequency Response and Frequency Bias Setting*[5] that would modify how the RLPCs and IFROs will be determined.

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[3] http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

[4] The most recent of which is the 2018 report. https://www.nerc.com/comm/OC/Documents/2018_FRAA_Report_Final.pdf

[5] http://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-1.1.pdf

Chapter 1: Study Scope and Method

Chapter 1 will discuss the proposed changes in determination of each Interconnection RLPC in addition to the methods used to validate the resulting IFROs.

Proposed Determination of RLPCs

The BAL-003-2 SDT is proposing to change the method used to determine the Interconnection RLPC in accordance with the following process:

NERC will request BAs to provide their two largest resource loss values and largest resource loss due to an N-1 or N-2 remedial action scheme (RAS) event. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be needed to complete the calculation of the RLPC and IFRO.

BAs determine the two largest resource losses for the next operating year based on a review of the following items:

- The two largest balancing contingency events due to a single contingency that is identified by using system models in terms of loss measured by megawatt loss in a normal system configuration (N-0). An abnormal system configuration is not used to determine the RLPC
- The two largest units in the BA Area, regardless of shared ownership/responsibility
- The two largest RAS resource losses (if any) that are initiated by single (N-1) contingency events

The BA provides these two numbers determined above as Resource Loss A and Resource Loss B.

The BA should then provide the largest resource loss due to RAS operations (if any) that is initiated by a multiple contingency (N-2) event. Note that RLPC cannot be lower than this value. If the RAS impacts more than a single BA, one BA is asked to take the lead and sum all resources lost due to the RAS event and provide that information.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.

The host BA (or planned host BA), where jointly-owned resources are physically located, should be the only BA to report that resource. The full ratings of the resource, not the fractional shares, should be reported.

Direct current (dc) ties to asynchronous resources, such as dc ties between Interconnections or the Manitoba Hydro Dorsey bi-pole ties to northern asynchronous generation. These dc lines, such as the Pacific DC Intertie (PDCI), which ties two sections of the same synchronous interconnection together, should not be reported. A single pole block with normal clearing in a monopole or bipole high-voltage dc system is a single contingency.

Based on initial review of data submitted to the BAL-003-2 SDT the proposed RLPC for each Interconnection is shown in **Table 1.1** and **Appendix B**.

Determination and Validation of Revised IFROs

Using the proposed RLPC values to recalculate the IFROs, the IFROs should be modified from those calculated in the *2017 Frequency Response Annual Analysis*[6] report as shown in **Table 1.1**. Both the maximum delta frequency and the credit for load resources (CLR) used in these calculations are from that report.

Table 1.1: Revised IFROs

	Eastern (EI)	Western (WI)	Texas (TI)	Québec (QI)	Units
Max. Allowable Delta Frequency	0.420	0.280	0.405	0.947	Hz
Proposed Resource Contingency Protection Criteria	3,209	2,850	2,750	2,000	MW
Credit for Load Resources	N/A	N/A	1,209	N/A	MW
Proposed IFROs	**-764**	**-1,018**	**-380**	**-211**	**MW/0.1 Hz**
Implemented 2017 IFROs	-1,015	-858	-381	-179	MW/0.1 Hz

Case Selection Process and Desired Attributes

Proper powerflow base case selection is essential to the process of IFRO validation especially since not all contingency elements of the proposed RLPCs are necessarily feasible for any single load level, resource dispatch, or inertia level. A balance must be struck between load levels, resource mix in the dispatch and the attendant inertia levels, and the contingencies against which the RLPCs are based.

With conventional synchronous generating resources, the lower the load level is the lower the generation dispatch, resulting in lower inertia and lower primary frequency response. Therefore, case selection would gravitate toward light-spring conditions. However, with today's high levels of photovoltaic inverter-based resources (IBRs), a lower inertia situation may occur in the middle of the day. Since photovoltaic IBR peak output is in the middle of the day with a growing portion "behind the meter," the net load that must be served by conventional generation resources is far lower than in the past, resulting in lower inertia levels. That situation is further complicated by blending higher penetrations of wind resources and the seasonal variability of water for hydroelectric generation, particularly in the WI.

For instance, loading on the California Oregon Interface (COI) and the Pacific DC Intertie (PDCI) must be high enough to arm and trigger the highest levels of generation tripping for the RAS to validate an IFRO based on an RLPC that includes the Pacific Northwest RAS in the WI. These conditions only exist during high water flows of spring runoff. However, high levels of hydro generation come with much higher levels of synchronous generation with a resultant higher inertia than would be seen in an equivalent light-load fall condition with lower water flows and lower hydro generation output.

Similarly, in the TI, very high levels of wind resource penetration result in counter-intuitive dispatch patterns that are sometimes constrained by ramping requirements for conventional generators and potential over-frequency conditions.

[6] https://www.nerc.com/comm/OC/Documents/2017_FRAA_Final_20171113.pdf

Procedure for Case Detuning

As built, each base case has its own inherent interconnection frequency response measurement (IFRM) linked to the dispatch and resource mix. That inherent case dispatch must be adjusted to match the proposed IFRO level in order to test the RLPCs at that frequency response level.

The following procedure was used on each case:

1. For the base case, determine the inherent IFRM for the contingencies in the RLPC and calculate the margin from the inherent Point C nadir to the highest level of UFLS for the Interconnection.
2. Reduce the frequency responsive reserves (FRRs) on the system by detuning the governors of the frequency responsive resources until the $IFRM_{A-B}$ equals the proposed $IFRO_{A-B}$. Perform this activity in several steps.

$$IFRM_{A-B} = \frac{MW\ Loss\ (RLPC)}{10*(Freq\ A - Freq\ B)} \leq Proposed\ IFRO_{A-B}$$

3. Determine the IFRM and calculate the margin from Point C nadir to UFLS for each detuning level.
4. When the case has been detuned to the level where $IFRM_{A-B}$ is equal to or less than the proposed $IFRO_{A-B}$ in absolute terms, evaluate whether the resulting Point C is higher than the Interconnection UFLS setting. If the Point C nadir is greater than the Interconnection UFLS then the proposed $IFRO_{A-B}$ is validated. If the resulting Point C is below the UFLS setting, reverse the detuning steps until Point C is above the UFLS setting and note the IFRM. The IFRO for that Interconnection must then be limited to that response level.
5. Graphically plot the frequency profiles for the base case and each detuning level showing the margins to the Interconnection UFLS set point.

IFROs and IFRMs are negative numbers because the change in MW output should be in the opposite direction as the change in frequency. For convenience purposes, references in this report to IFROs and IFRMs will often be in terms of absolute value.

It is important to recognize that the results of the dynamic studies should be considered conservative in nature since the impact of load response and load damping are not modeled.

Chapter 2: IFRO Validation for Each Interconnection

Chapter 2 details the approach for case selection, identifying desired case attributes, the results of each detuning step, and the process for validation of the proposed IFROs through time domain simulation. Results and key findings are summarized in this chapter.

Eastern Interconnection

This analysis is a validation of the proposed IFRO for the EI using a Light Load Base Case. The 2018 Year Operating Base Case was developed by incorporating actual governor response data and modeling parameters obtained from the Generator Owners and Generator Operators during survey processes. This data was incorporated during the building process for the 2018-LL Light Load Dynamics Base Case.

Interconnection Characteristics

Table 2.1 shows the statistical EI load and inertia characteristics based on the 2018 FERC Form 714 submittals (2017 data) and 2018 inertia data collected for essential reliability services (ERS) measurements as well as the base case attributes.

Table 2.1: Eastern Interconnection Characteristics

Interconnection Load	MW
10th Percentile Interconnection Load	265,004
90th Percentile Interconnection Load	416,188
Peak Load	564,733
Interconnection Inertia	**GW-seconds**
10th Percentile Interconnection Inertia	1,302
90th Percentile Interconnection Inertia	1,851
Base Case Attributes	
Base Case Load (MW)	325,181
Base Case Inertia (GW-seconds)	1,506
Base Case Frequency Responsive Reserves (MW)	26,619

Selected Base Case Description and Attributes

The EI frequency response is resilient under peak load conditions due to the amount of dispatched generation resulting in a large system inertia. The 2018-LL Light Load Dynamics Base Case was the only case studied for the IFRO analysis because this case models a relatively light load low inertia operating scenario.

Dispatch and Case Modifications

The base case did not include sufficient loading on the Dorsey bipole terminals to meet the recommended RLPC criteria, so the Manitoba dc tie-line Base Case set value was increased from 710 MW to 1,732 MW. To accommodate this change in power flow, Henday Generation was increased to provide a source for the increased Dorsey bipole set value. Additional generation was reduced in Area 600, and the net load was reduced by 600 MW in the Manitoba Hydro assessment area. The EI IFRO evaluation was performed by detuning the governor performance in the base case. The amount of FRRs on the system was decreased in successive steps until it approached the proposed IFRO of

764 MW/0.1 Hz for a loss of the RLPC of 3,209 MW. The resulting nadir was then compared to 59.5 Hz, the highest EI UFLS set point.

Results and Key Findings

The BAL-003-2 SDT recommended a reduction in the EI RLPC from 4,500 MW to 3,209 MW with the resulting IFRO phased in over three increments following evaluation of each previous reduction. The initial reduction in IFRO would be from the current 1,015 to 915 MW/0.1 Hz followed by subsequent reductions to 815 and 764 MW/0.1 Hz.

EI Findings

Dynamic simulations successfully validated an EI IFRO as low as 787 MW/0.1 Hz with a resulting minimum Point C frequency nadir of 59.511 Hz. This is 11 mHz above the EI UFLS of 59.500 Hz.

The base case had a total Interconnection load of 325,181 MW and inertia of 1,506 GW-seconds with 26,619 MW of FRR at the EI recommended droop setting[7] of 5%. Loss of the proposed RLPC of 3,209 MW was simulated using the base case and resulted in a minimum Point C frequency nadir of 59.890 Hz versus an Interconnection UFLS of 59.500 Hz. The starting frequency of 59.974 Hz was statistically determined in the 2017 FRAA report. The settled frequency of Value B was 59.897 Hz resulting in a calculated $IFRM_{A\text{-}B}$ of 4,161 MW/0.1 Hz.

Four subsequent levels of detuning were simulated as shown in **Table 2.2 and Figure 2.1**. The load and inertia were unchanged for the detuning simulations. The levels were as follows:

- For detuning Level 1, the amount of FRR was reduced to 23,741 MW, or 7.30% of Interconnection load; this resulted in a calculated $IFRM_{A\text{-}B}$ of 2,099 MW/0.1 Hz and a minimum Point C frequency nadir of 59.817 Hz.
- For detuning Level 2, the amount of FRR was reduced to 11,682 MW, or 3.59% of Interconnection load; this resulted in a calculated $IFRM_{A\text{-}B}$ of 1,352 MW/0.1 Hz and a minimum Point C frequency nadir of 59.728 Hz.
- For detuning Level 3, the amount of FRR was reduced to 4,832 MW, or 1.49% of Interconnection load; this resulted in a calculated $IFRM_{A\text{-}B}$ of 956 MW/0.1 Hz and a minimum Point C frequency nadir of 59.601 Hz.
- For detuning Level 4, the amount of FRR was reduced to 2,114 MW, or 0.65% of Interconnection load; this resulted in a calculated $IFRM_{A\text{-}B}$ of 787 MW/0.1 Hz and a minimum Point C frequency nadir of 59.511 Hz.

[7] https://www.nerc.com/comm/OC_Reliability_Guidelines_DL/PFC_Reliability_Guideline_rev20190501_v2_final.pdf

Table 2.2: Eastern Interconnection Detuning Summary					
	Base Case	Detune1	Detune2	Detune3	Detune4
EI Load (MW)	325,181	325,181	325,181	325,181	325,181
On-line Generation (MW)	330,236	330,236	330,236	330,236	330,236
EI Inertia (GW-sec)	1,506	1,506	1,506	1,506	1,506
FRR (MW @ 5% droop)	26,619	23,741	11,682	4,832	2,114
FRR % Load	8.19%	7.30%	3.59%	1.49%	0.65%
RLPC (MW)	3,209	3,209	3,209	3,209	3,209
Starting Freq Pt A (Hz)	59.974	59.974	59.974	59.974	59.974
Min Freq Pt C (Hz)	59.890	59.817	59.728	59.601	59.511
Time Min Freq (sec)	5.867	18.971	23.160	36.015	40.401
Settled Freq Value B (Hz)	59.897	59.821	59.737	59.638	59.566
Proposed $IFRO_{A-B}$ (MW/0.1 Hz)*	915/815/764	915/815/764	915/815/764	915/815/764	915/815/764
$IFRM_{A-B}$ (MW/0.1 Hz)	**4,161**	**2,099**	**1,352**	**956**	**787**

* The proposed EI IFRO will be reduced in three increments pending evaluation of the previous reduction.

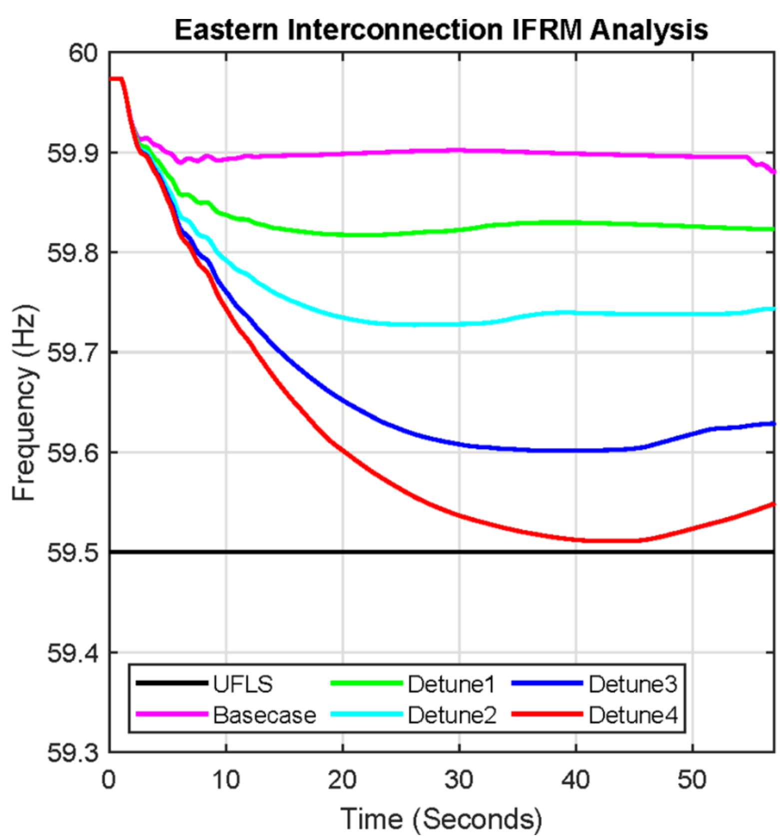

Figure 2.1: Eastern Interconnection Base Case and Detuning Graphs

Conclusion

The aforementioned dynamic simulations successfully validated an EI IFRO as low as 787 MW/0.1 Hz with a resulting minimum Point C frequency nadir of 59.511 Hz; which is 11 mHz above the EI UFLS of 59.500 Hz. It is important to recognize that the results of the dynamic studies should be considered conservative in nature since the impact of load response and load damping are not modeled.

Western Interconnection

This analysis is a validation of the proposed IFRO for the WI. The WI proposed RLPC was selected by the SDT to be the Northwest Remedial Action Scheme (RAS). Previously two Palo Verde (2PV) nuclear units were used as the RPLC for the WI. In this study the 2PV simulation was also performed as a sensitivity analysis.

Interconnection Characteristics

Table 2.3 shows the statistical load and inertia characteristics for WI based on the 2018 FERC Form 714 submittals (2017 data) and inertia data collected for essential reliability services measurements as well as the base case attributes.

Table 2.3: Western Interconnection Characteristics	
Interconnection Load	
10th Percentile Interconnection Load (MW)	75,758
90th Percentile Interconnection Load (MW)	119,273
Peak Load (MW)	170,862
Interconnection Inertia	
10th Percentile Interconnection Inertia (GW-seconds)	540
90th Percentile Interconnection Inertia (GW-seconds)	695
Base Case A Attributes: RLPC = RAS	
Base Case Load (MW)	82,634
Base Case Inertia (GW-seconds)	527
Base Case Frequency Responsive Reserves (MW)	50,689
Base Case B Attributes: RLPC = 2PV	
Base Case Load (MW)	108,245
Base Case Inertia (GW-seconds)	674
Base Case Frequency Responsive Reserves (MW)	24,118

Selected Base Cases Description and Attributes

Two cases were developed for the 2018 operating year. Case A was developed with a State Estimator Node Breaker Case for April 7, 2017, 0600 UTC. The RLPC is the Northwest RAS with a loss of 2,850 MW. Case B is the 2019 Light Summer Planning Case. The RLPC is two Palo Verde units (1 and 3) with a combined loss of 2,775 MW.

Case A: On-line generation profile from the energy management system (EMS) snapshot April 7, 2017, 0600 UTC

- RLPC Simulation = High-water semi-light load trips of the PDCI and activation of the RAS
- Interconnection Load = 82,634 MW
- Interconnection Inertia of 527 GW-sec and Interconnection Load of 82.6 GW
- Base Case Frequency Responsive Reserve (FRR) = 50,689 MW

Case B: **2019 Light Summer Planning Case**

- RLPC Simulation = 2,775 MW for the trip of two Palo Verde nuclear units.
- Interconnection Load = 108,245 MW
- Interconnection Inertia = 674 GW-seconds
- Base Case Frequency Responsive Reserve (FRR) = 24,118 MW

Case A: Results and Key Findings

The BAL-003-2 SDT recommended an increase in the WI RLPC from 2,626 MW to 2,850 MW with the resulting IFRO increasing from 858 to 1,018 MW/0.1 Hz.

WI Finding
Dynamic simulations successfully validated a WI IFRO as low as 1,013 MW/0.1 Hz with a resulting minimum Point C frequency nadir of 59.534 Hz; this is 34 mHz above the WI UFLS of 59.500 Hz.

The base case had a total Interconnection load of 82,634 MW and inertia of 527 GW-seconds with 50,689 MW of FRR and 61.3% of total Interconnection load at the recommended WI droop setting of 5%. Loss of the proposed RLPC of 2,850 MW was simulated using the base case and resulted in a minimum Point C frequency nadir of 59.615 Hz versus an Interconnection UFLS of 59.500 Hz. The starting frequency of 59.966 Hz was statistically determined in the *2018 FRAA* report. Settled frequency Value B was 59.785 Hz resulting in a calculated $IFRM_{A-B}$ of 1,581 MW/0.1 Hz.

Four subsequent levels of detuning were simulated as shown in Table 2.4 and Figure 2.2. The load and inertia were unchanged for the detuning simulations. The levels were as follows:

- For detuning Level 1, the amount of FRR was reduced to 46,037 MW, or 55.71% of Interconnection load; this resulted in a calculated $IFRM_{A-B}$ of 1,477 MW/0.1 Hz and a minimum Point C frequency nadir of 59.597 Hz.
- For detuning Level 2, the amount of FRR was reduced to 41,288 MW, or 49.97% of Interconnection load; this resulted in a calculated $IFRM_{A-B}$ of 1,382 MW/0.1 Hz and a minimum Point C frequency nadir of 59.581 Hz.
- For detuning Level 3, the amount of FRR was reduced to 34, 145MW, or 41.32% of Interconnection load; this resulted in a calculated $IFRM_{A-B}$ of 1,098 MW/0.1 Hz and a minimum Point C frequency nadir of 59.555 Hz.
- For detuning Level 4, the amount of FRR was reduced to 31,028 MW, or 37.55% of Interconnection load; this resulted in a calculated $IFRM_{A-B}$ of 1,013 MW/0.1 Hz and a minimum Point C frequency nadir of 59.534 Hz.

Table 2.4: Western Interconnection Detuning Summary – NW RAS

	Base Case	Detune1	Detune2	Detune3	Detune4
WI Load (MW)	82,634	82,634	82,634	82,634	82,634
On-line Generation (MW)	85,453	85,453	85,453	85,453	85,453
WI Inertia (GW-sec)	527	527	527	527	527
FRR (MW @ 5% droop)	50,689	46,037	41,288	34,145	31,028
FRR % Load	61.34%	55.71%	49.97%	41.32%	37.55%
RLPC (MW)	2,850	2,850	2,850	2,850	2,850
Starting Freq Pt A (Hz)	59.966	59.966	59.966	59.966	59.966
Min Freq Pt C (Hz)	59.615	59.597	59.581	59.555	59.534
Time Min Freq (sec)	6.517	6.567	6.654	8.967	8.967
Settled Freq Value B (Hz)	59.785	59.773	59.759	59.706	59.684
Proposed $IFRO_{A-B}$ (MW/0.1 Hz)	1,018	1,018	1,018	1,018	1,018
$IFRM_{A-B}$ (MW/0.1 Hz)	**1,581**	**1,477**	**1,382**	**1,098**	**1,013**

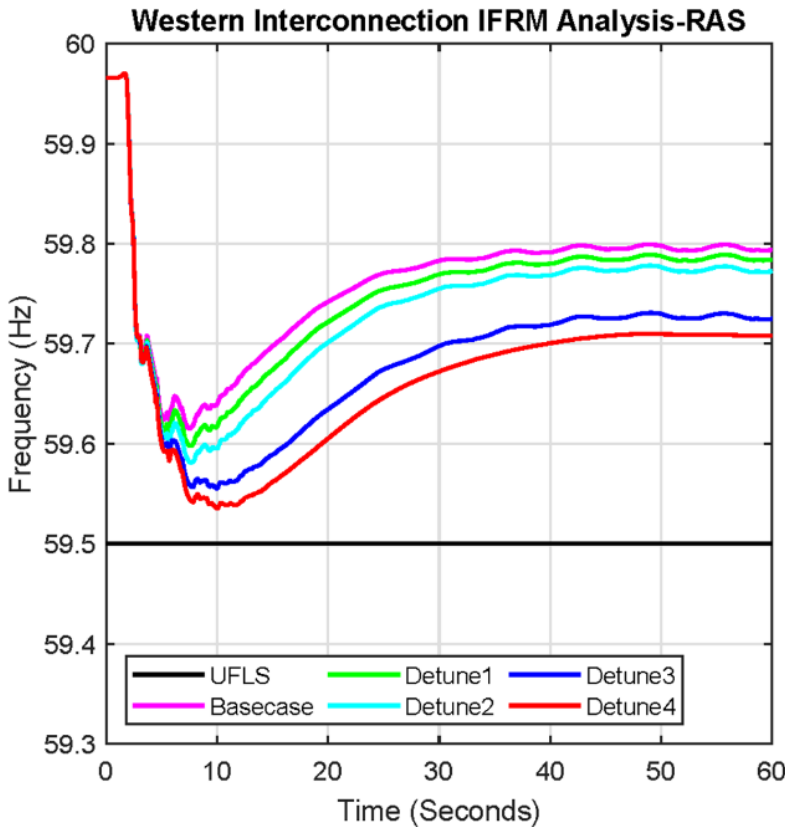

Figure 2.2: Western Interconnection Base Case and Detuning Graphs

Conclusion for Case A

The aforementioned dynamic simulations successfully validated a WI IFRO as low as 1,013 MW/0.1 Hz with a resulting minimum Point C frequency nadir of 59.534 Hz; this is 34 mHz above the WI UFLS of 59.500 Hz. It is important to recognize that the results of the dynamic studies should be considered conservative in nature since the impact of load response and load damping are not modeled.

Case B: Results and Key Findings

Case B is a sensitivity analysis using a WI RLPC of 2,775 MW for the loss of two Palo Verde units. The purpose of this analysis is to simulate a contingency in the southern part of the WI in addition to the Northwest RAS simulated in Case A. The aforementioned proposed IFRO of 1,018 MW/0.1 Hz is used for validation purposes.

The base case had a total Interconnection load of 108,245 MW and inertia of 674 GW-seconds with 24,118 MW of FRR at the recommended WI droop setting of 5%. Loss of the proposed RLPC of 2,775 MW was simulated using the base case and resulted in a minimum Point C frequency nadir of 59.681 Hz versus an Interconnection UFLS of 59.500 Hz. The starting frequency of 59.966 Hz was statistically determined in the *2018 FRAA* report. Settled frequency Value B was 59.810 Hz resulting in a calculated $IFRM_{A\text{-}B}$ of 1,770 MW/0.1 Hz.

Four subsequent levels of detuning were simulated as shown in Table 2.5 and Figure 2.3. The load and inertia were unchanged for the detuning simulations. The levels were as follows:

- For detuning Level 1, the amount of FRR was reduced to 22,467 MW, or 20.76% of Interconnection load; this resulted in a calculated $IFRM_{A\text{-}B}$ of 1,600 MW/0.1 Hz and a minimum Point C frequency nadir of 59.670 Hz.
- For detuning Level 2, the amount of FRR was reduced to 19,558 MW, or 18.07% of Interconnection load; resulted in a calculated $IFRM_{A\text{-}B}$ of 1,316 MW/0.1 Hz and a minimum Point C frequency nadir of 59.648 Hz.

- For detuning Level 3, the amount of FRR was reduced to 16,212 MW, or 14.98% of Interconnection load; this resulted in a calculated $IFRM_{A-B}$ of 1,082 MW/0.1 Hz and a minimum Point C frequency nadir of 59.626 Hz.
- For detuning Level 4, the amount of FRR was reduced to 15,180 MW, or 14.02% of Interconnection load; this resulted in a calculated $IFRM_{A-B}$ of 1,010 MW/0.1 Hz and a minimum Point C frequency nadir of 59.611 Hz.

Table 2.5: Western Interconnection Detuning Summary – 2PV

	Base Case	Detune1	Detune2	Detune3	Detune4
WI Load (MW)	108,245	108,245	108,245	108,245	108,245
On-line Generation (MW)	111,782	111,782	111,782	111,782	111,782
WI Inertia (GW-sec)	674	674	674	674	674
FRR (MW @ 5% droop)	24,118	22,467	19,558	16,212	15,180
FRR % Load	22.28%	20.76%	18.07%	14.98%	14.02%
RLPC (MW)	2,775	2,775	2,775	2,775	2,775
Transmission Losses (MW)	433	433	433	433	433
Starting Freq Pt A (Hz)	59.966	59.966	59.966	59.966	59.966
Min Freq Pt C (Hz)	59.681	59.670	59.648	59.626	59.611
Time Min Freq (sec)	7.079	7.192	9.267	11.704	11.816
Settled Freq Value B (Hz)	59.810	59.794	59.757	59.711	59.693
Proposed $IFRO_{A-B}$ (MW/0.1 Hz)	1,018	1,018	1,018	1,018	1,018
$IFRM_{A-B}$ (MW/0.1 Hz)	**1,770**	**1,600**	**1,316**	**1,082**	**1,010**

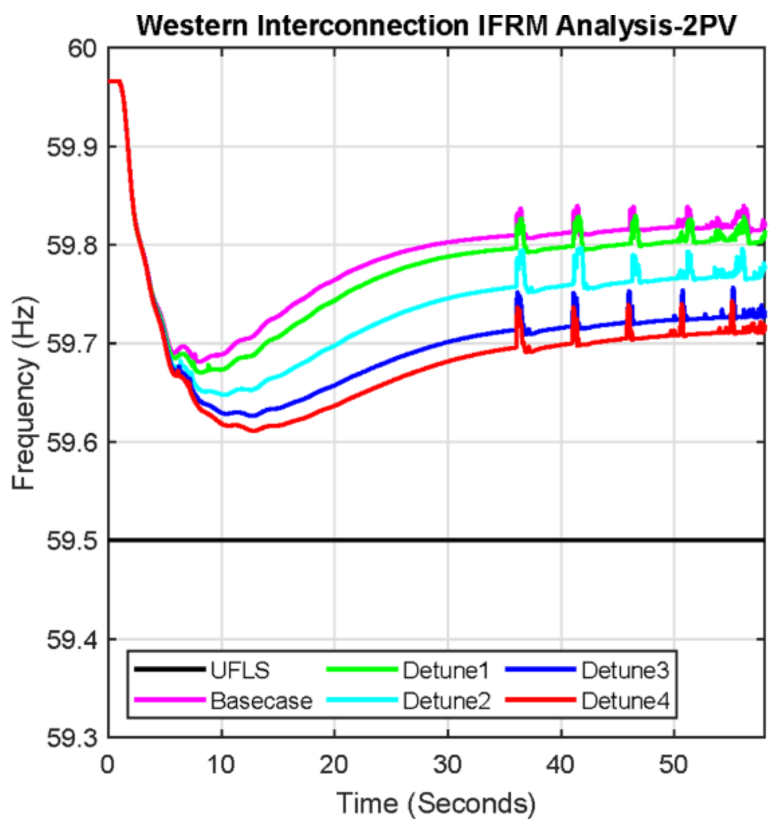

Figure 2.3: Western Interconnection Base Case and Detuning Graph

Figure 2.3 shows spikes beyond 30 seconds during the simulation that are attributed to the need, when simulating the loss of 2 Palo Verde units, to adjust the planning case prior to simulation in an attempt to match average system inertia conditions. Such adjustments may create interactions with widespread small MVA generating units across the planning case that are usually netted. The simulation graph (Figure 2.3) demonstrates those interactions. Additionally, many of those units are modeled at the sub-transmission buses with the parameters from the machine test results or other databases. Due to such modeling the small units can create numerical “blips” after a large disturbance pushing them into an operating range allowable by the model but not tuned to represent the unit’s response.

Conclusion for Case B

The aforementioned dynamic simulations successfully validated a WI IFRO as low as 1,010 MW/0.1 Hz with a resulting minimum Point C frequency nadir of 59.611 Hz; this is 111 mHz above the WI UFLS of 59.500 Hz. It is important to recognize that the results of the dynamic studies should be considered conservative in nature since the impact of load response and load damping are not modeled.

Texas Interconnection

This analysis is a validation of the proposed IFRO for the TI using a Light Load Base Case. The 2021 Light Spring Year Base Case was developed by adapting the 2021 High Wind Case using the generation dispatch and load profile from an EMS snapshot.

Interconnection Characteristics

Table 2.6 shows the statistical TI load and inertia characteristics based on the 2018 FERC Form 714 submittals (2017 data) and inertia data collected for essential reliability service measurements as well as the base case attributes.

Table 2.6: Texas Interconnection Characteristics	
Interconnection Load	
10th Percentile Interconnection Load (MW)	30,347
90th Percentile Interconnection Load (MW)	55,074
Peak Load (MW)	73,473
Interconnection Inertia	
10th Percentile Interconnection Inertia (GW-seconds)	181
90th Percentile Interconnection Inertia (GW-seconds)	337
Base Case Attributes	
Base Case Load (MW)	27,400
Base Case Inertia (GW-seconds)	143
Base Case Frequency Responsive Reserves (MW)	4,537

Selected Base Case Description and Attributes

The 2021 Spring Light Case with Interconnection inertia of 143 GW-sec and Interconnection load of 27.4 GW was used for the base case. The on-line generation profile and dispatch scenario from the EMS snapshot were used.

Other Cases Considered

Initially, the 2021 High Wind Case that was provided to represent a high wind generation dispatch and corresponding load level greater than the Minimum Case but lower the Summer Peak Case. However, the spinning reserve in that was considered high and it has 209 GW-sec of interconnection inertia.

Dispatch and Case Modifications

Replace the generation values of the 2021 HW by the provided EMS snapshot and scale the load down from 53 GW to 27.4 GW.

Results and Key Findings

The BAL-003-2 SDT recommended no change in the TI RLPC of 2,750 MW with the IFRO decreasing slightly from 381 to 380 MW/0.1 Hz.

TI Findings

Dynamic simulations successfully validated a TI IFRO as low as 378.1 MW/0.1 Hz with a resulting minimum Point C frequency nadir of 59.302 Hz; this is 2 mHz above the TI UFLS of 59.300 Hz.

The base case had a total Interconnection load of 27,400 MW and inertia of 143 GW-seconds with 4,537 MW of FRR, 16.56% of total Interconnection load, at the Texas RE recommended droop setting of 5%. Loss of the proposed RLPC of 2,750 MW with the load resources credit of 1209 MW that triggered at 59.7 Hz were simulated using the base case and resulted in a minimum Point C frequency nadir of 59.526 Hz versus an Interconnection UFLS of 59.300 Hz. The starting frequency of 59.968 Hz was statistically determined in the 2017 FRAA report. Settled frequency Value B was 59.790 Hz resulting in a calculated $IFRM_{A-B}$ of 886.3 MW/0.1 Hz.

Four subsequent levels of detuning were simulated as shown in Table 2.8 and Figure 2.4. The load and inertia were unchanged for the detuning simulations. The levels were as follows:

- For detuning Level 1, the amount of FRR was reduced to 3,540 MW, or 12.92% of Interconnection load; this resulted in a calculated $IFRM_{A-B}$ of 709.9 MW/0.1 Hz and a minimum Point C frequency nadir of 59.485 Hz.
- For detuning Level 2, the amount of FRR was reduced to 2,538 MW, or 9.26% of Interconnection load; this resulted in a calculated $IFRM_{A-B}$ of 592.2 MW/0.1 Hz and a minimum Point C frequency nadir of 59.438 Hz.
- For detuning Level 3, the amount of FRR was reduced to 1,486 MW, or 5.42% of Interconnection load; this resulted in a calculated $IFRM_{A-B}$ of 432.4 MW/0.1 Hz and a minimum Point C frequency nadir of 59.345 Hz.
- For detuning Level 4, the amount of FRR was reduced to 482 MW, or 1.76% of Interconnection load; this resulted in a calculated $IFRM_{A-B}$ of 378.1 MW/0.1 Hz and a minimum Point C frequency nadir of 59.302 Hz.

Table 2.8: Texas Interconnection Detuning Summary

	Base Case	Detune1	Detune2	Detune3	Detune4
TI Load (MW)	27,400	27,400	27,400	27,400	27,400
On-line Generation (MW)	31,850	31,850	31,850	31,850	31,850
TI Inertia (GW-sec)	143	143	143	143	143
FRR (MW @ 5% droop)	4,537	3,540	2,538	1,486	482
FRR % Load	16.56%	12.92%	9.26%	5.42%	1.76%
RLPC (MW)	2,750	2,750	2,750	2,750	2,750
Load Resources Credit (MW)	1,209	1,209	1,209	1,209	1,209
Starting Freq Pt A (Hz)	59.968	59.968	59.968	59.968	59.968
Min Freq Pt C (Hz)	59.526	59.485	59.438	59.345	59.302
Time Min Freq (sec)	2.404	3.337	5.775	6.567	6.867

Table 2.8: Texas Interconnection Detuning Summary					
	Base Case	Detune1	Detune2	Detune3	Detune4
Settled Freq Value B (Hz)	59.790	59.751	59.708	59.612	59.560
Proposed $IFRO_{A-B}$ (MW/0.1 Hz)	380	380	380	380	380
$IFRM_{A-B}$ (MW/0.1 Hz)	**866**	**710**	**592**	**432**	**378**

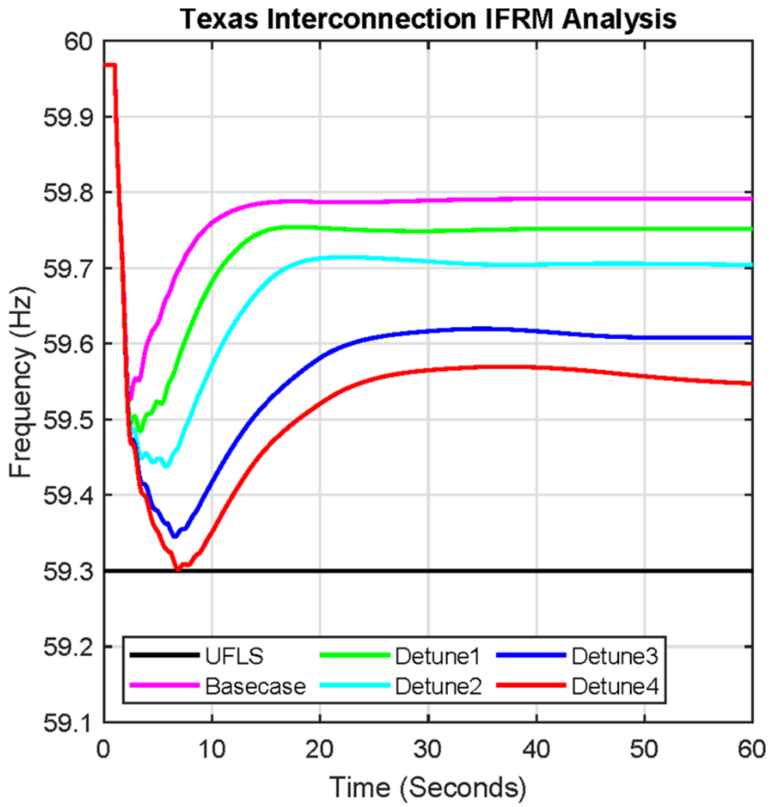

Figure 2.4: Texas Interconnection Base Case and Detuning Graphs

Conclusion

The aforementioned dynamic simulations successfully validated a TI IFRO as low as 378 MW/0.1 Hz with a resulting minimum Point C frequency nadir of 59.302 Hz; this is 2 mHz above the TI UFLS of 59.300 Hz. It is important to recognize that the results of the dynamic studies should be considered conservative in nature since the impact of load response and load damping are not modeled.

Appendix A: Definitions

Note that IFROs and IFRMs are negative numbers because the change in MW output should be in the opposite direction as the change in frequency. For convenience purposes, references in this report to IFROs and IFRMs will be in terms of absolute value.

Interconnection Frequency Response Obligation: IFRO is the minimum amount of frequency response that must be maintained by an interconnection in order to avoid activation of the first stages of UFLS.[8]

Value A: The average pre-disturbance frequency for the period T-16 through T+0 seconds

Value B: The post-disturbance frequency for the period T+20 through T+52 seconds is defined as the settled frequency response.

Point C: The point at which the frequency decline of an event is arrested, often called the nadir.

Interconnection Frequency Response Measurement: IFRM is the measured frequency response of the interconnection calculated as:

$$IFRM_{A-B} = \frac{MW\ Loss}{10 * \Delta f_{A-B}}$$

Where:

MW Loss = Resource or Load Output immediately prior to the start of the event

Δf_{A-B}= Change in frequency from Value A to Value B Change in frequency from Value A to Value B

Resource Loss Protection Criteria: RLPC was originally determined in the *2012 Frequency Response Initiative Report*[4] and are shown in **Table A.1**.

Table A.1: Original RLPCs

Interconnection	RLPC Description	MW	Criteria
Eastern	2007 EI Frequency Event	4,500	Largest Resource Event in Last 10 Years
Western	Loss of 2 Palo Verde Units	2,740	Largest N-2 Resource Loss Event
ERCOT	Loss of South Texas Project	2,750	Largest Total Plant with Common Voltage Switchyard
Québec		1,700	Operating Loss Criteria

[8] IFRO is described in detail in the *2012 Frequency Response Initiative* Report at: http://www.nerc.com/docs/pc/FRI_Report_10-30-12_Master_w-appendices.pdf

Appendix B: Interconnection RLPC Values

Based on initial review, the numbers below are representative of the RLPC for each Interconnection proposed by BAL-003-2 SDT.

Eastern Interconnection:
Present RLPC = 4,500 MW Load Credit = 0 MW
RESOURCE LOSS A = 1,732 MW
RESOURCE LOSS B = 1,477 MW
Proposed RLPC = 3,209 MW

Western Interconnection:
Present RLPC = 2,626 MW Load Credit = 0 MW
RESOURCE LOSS A = 1,505 MW
RESOURCE LOSS B = 1,344 MW
N-2 RAS = 2,850 MW
Proposed RLPC = 2,850 MW

ERCOT:
Present RLPC = 2,750 MW Load Credit = 1,209 MW
RESOURCE LOSS A = 1,375 MW
RESOURCE LOSS B = 1,375 MW
Proposed RLPC = 2,750 MW

Quebec Interconnection:
Present RLPC = 1,700 MW Load Credit = 0 MW
RESOURCE LOSS A = 1,000 MW
RESOURCE LOSS B = 1,000 MW
Proposed RLPC = 2,000 MW

Appendix C: Calculation of IFRO Values

The IFRO is calculated using the RLPC as shown in Table C.1

$$\text{IFRO} = \frac{(\text{RLPC-CLR})}{(\text{MDF*10})} \quad \text{expressed as MW/0.1Hz}$$

MDF is the Maximum Delta Frequency for the specific interconnection as determined in the 2017 Frequency Response Annual Analysis (FRAA).

Table C.1: Interconnection Frequency Response Obligation

	Eastern	Western	ERCOT	HQ	Units
Max. Delta Frequency	0.420	0.280	0.405	0.947	Hz
Resource Loss Protection Criteria	3,209	2,850	2,750	2,000	MW
Credit for Load Resources	0	0	1,209	0	MW
Calculated IFRO	-764*	-1018	-380	-211	MW/0.1Hz

* The proposed EI IFRO will be reduced in three increments pending evaluation of the previous reduction.

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Exhibit G

Proposed Resource Loss Protection Criteria

Proposed Resource Loss Protection Criteria

Background and Current Methodologies

The Resource Loss Protection Criteria (RLPC) is the respective Interconnection design resource loss in MW, which is used to determine the Interconnection Frequency Response Obligation (IFRO).
An “N-2 Event” is defined as a single initiating event that leads to multiple (two or more) electrical facilities being removed from service. Examples of this are breaker failure events, bus faults, or double circuit tower outages.

Previously, the RLPC has been calculated from the largest N-2 events identified in each Interconnection, except for the Eastern Interconnection. In the Eastern Interconnection, the RLPC has been calculated using the largest single event in the previous ten years.

The RLPC value should be set for each Interconnection such that the underfrequency load shedding safety net is not activated for the largest N-2 Event. The previous BAL-003 IFRO methodology determined that the largest N-2 Event should not precipitate an underfrequency load shedding event. Ideally, the RLPC value should always equal or exceed the largest N-2 Event. If the RLPC is set to a larger value than the largest N-2 Event, the probability of an underfrequency load shedding event decreases. If the RLPC value is set to a value less than the largest N-2 Event, the probability of an underfrequency load shedding event increases.

A quantitative approach for selecting the RLPC can be implemented that minimizes the need for detailed system analysis to be performed annually.

Currently, each Balancing Authority (BA) or Reserve Sharing Group (RSG) determines its Most Severe Single Contingency (MSSC) with respect to resource loss as required by BAL-002-2(i), Requirement R2. The MSSC calculation is done in Real-time operations based on actual system configuration.

Relevant Definitions

For convenience, the definitions of the following terms defined in the Glossary of Terms used in NERC Reliability Standards are provided below. Where a conflict exists between the definition provided here and the definition in the Glossary, the definition in the Glossary shall control.

Most Severe Single Contingency:
The Balancing Contingency Event, due to a single contingency identified using system models maintained within the RSG or a BA’s area that is not part of a RSG, that would result in the greatest loss (measured in Megawatts (MWs) of resource output used by the RSG or a BA that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Balancing Contingency Event:
Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less.

A. Sudden loss of generation:
   a. Due to:
      i. unit tripping, or
      ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or
      iii. sudden unplanned outage of transmission Facility.
   b. And that causes an unexpected change to the responsible entity's Area Control Error (ACE).
B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.
C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Interconnection:
A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

Proposal
The Interconnection RLPC is calculated based on a resource loss in accordance with the following process:

NERC will request BAs to provide their two largest resource loss values and largest resource loss due to an N-1 or N-2 RAS event. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be needed to complete the calculation of the RLPC and IFRO.

BAs determine the two largest resource losses for the next operating year based on a review of the following items:

- The two largest independent Balancing Contingency Events, each due to a single contingency, identified using system models measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)
- The two largest units in the BA Area, regardless of shared ownership/responsibility.

- The two largest Remedial Action Scheme (RAS) resource losses (if any) which are initiated by single (N-1) contingency events.

The BA provides these two numbers determined above as Resource Loss A and Resource Loss B in the FRS Form 1.

The BA should then provide the largest resource loss due to RAS operations (if any) which is initiated by a multiple contingency (N-2) event (RLPC cannot be lower than this value). If the RAS impacts more than a single BA, one BA is asked to take the lead and sum all resources lost due to the RAS event and provide that information.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.

The host BA (or planned host BA) where jointly-owned resources are physically located, should be the only BA to report that resource. The full ratings of the resource, not the fractional shares, should be reported.

Direct-current (DC) ties to asynchronous resources (such as DC ties between Interconnections, or the Manitoba Hydro Dorsey bi-pole ties to their northern asynchronous generation) should be considered as resources losses. DC lines, such as the Pacific DC Intertie, which ties two sections of the same synchronous interconnection together, should not be reported. A single pole block with normal clearing in a monopole or bi-pole high-voltage direct current system is a single contingency.

For a hypothetical four-BA Interconnection, Plant 1, in BA1, has two generators rated at 1200 MW each. Plant 2, in BA2 has a generator rated at 1400 MW. BA2’s next largest contingency is 1000 MW. The two largest resource losses for BA3 and BA4 are listed below.

BA1	Resource Loss A = 1200 MW	Resource Loss B = 1200 MW	Both at Plant 1 (N-2)
BA2	Resource Loss A= 1400 MW	Resource Loss B = 1000 MW	Electrically separate
BA3	Resource Loss A = 1000 MW	Resource Loss B = 800 MW	Electrically separate
BA4	Resource Loss A = 1500 MW (DC TIE)	Resource Loss B= 500 MW	Electrically separate

The ERO would apply the RLPC selection methodology described above to determine the RLPC for the Interconnection. Using this methodology, results in the following:

Largest Resource Loss = 1500 MW
Second Largest Resource Loss = 1400 MW
Summation of two largest resource losses = 2900 MW
Interconnection RLPC = 2900 MW

If only the N-2 Event was applied, the RLPC for the Interconnection would be 2400 MW. The summation of the two largest Interconnection Resource Losses will equal or exceed, but never fall short of, the N-2 Event scenario.

In order to evaluate RAS resource loss, single (N-1) and multiple (N-2) contingency events should be evaluated.

Hypothetically, in an Interconnection:

BA1 RAS = 2850 MW N-2 RAS event
BA1 Resource Loss A = 1150 MW
BA1 Resource Loss B = 800 MW
BA2 Resource Loss A = 1380 MW
BA2 Resource Loss B = 1380 MW
BA3 RAS = 1000 MW N-1 RAS event
BA3 Resource Loss A = 800 MW
BA3 Resource Loss B = 700 MW

In this case, the ERO would determine the RLPC as follows: the summation of the two largest resource losses is 2760 MW. Since the N-2 RAS event exceeds the summation of the two largest single contingency events, the RLPC is the N-2 RAS event, or 2850 MW.

Interconnection RLPC Values

Based on initial review, the numbers below would be representative of the RLPC for each Interconnection.

Eastern Interconnection:
Present RLPC = 4500 MW Load Credit = 0 MW
RESOURCE LOSS A = 1732 MW
RESOURCE LOSS B = 1477 MW
Proposed RLPC = 3209 MW

Western Interconnection:
Present RLPC = 2626 MW Load Credit = 0 MW
RESOURCE LOSS A = 1505 MW
RESOURCE LOSS B = 1344 MW
N-2 RAS = 2850 MW
Proposed RLPC = 2850 MW

ERCOT:
Present RLPC = 2750 MW Load Credit = 1209 MW
RESOURCE LOSS A = 1375 MW
RESOURCE LOSS B = 1375 MW
Proposed RLPC = 2750 MW

Quebec Interconnection:
Present RLPC = 1700 MW Load Credit = 0 MW
RESOURCE LOSS A = 1000 MW

RESOURCE LOSS B = 1000 MW
Proposed RLPC = 2000 MW

Exhibit H

Standard Drafting Team Roster

Project 2017-01 Modifications to BAL-003-1.1

Standard Drafting Team Roster

Name	Company	
David Lemmons	Ethos Energy Group	Chair
Rich Hydzik	Avista	Vice-chair
Thomas V. Pruitt	Duke Energy	Member
Greg Park	Northwest Power Pool	Member
Danielle Croop	PJM Interconnection	Member
Daniel Baker	Southwest Power Pool	Member
Sandip Sharma	ERCOT	Member
William (Bill) Shultz	Southern Company	Member
Antonio Franco	Gridforce	Member
Joshua Boone	LG&E and KU Services Co.	Member
Jessica Tang	IESO	Member
Laura Anderson	NERC - Standards Developer	NERC Staff
Darrel Richardson	NERC - Principal Technical Advisor	NERC SME
Bob Cummings	NERC - Senior Director	NERC SME
Brad Gordon	NERC - Manager	NERC SME
Candice Castaneda	NERC - Legal	
Lauren Perotti	NERC - Legal	

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Exhibit I

Summary of Development
and Complete Record of Development

Summary of Development History

The following is a summary of the development record for proposed Reliability Standard BAL-003-2.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team ("SDT") selected to lead each project in accordance with Section 4.3 of the NERC Standard Processes Manual, Appendix 3A to the NERC Rules of Procedure.[2] For this project, the SDT consisted of industry experts, all with a diverse set of experiences. A roster of the Project 2017-01 – Modifications to BAL-003-1.1 SDT members is included in **Exhibit H**.

II. Standard Development History

A. Standard Authorization Request Development

On June 14, 2017, the Standards Committee authorized posting a Standards Authorization Request ("SAR") as well as the solicitation of nominations for the Project 2017-01 – Modifications to BAL-003-1.1 SDT.[3] The SAR was posted for a 30-day informal comment period from June 19, 2017 through July 18, 2017 and the drafting team nominations were open from June 19, 2017 through July 3, 2017. The SAR received 17 sets of responses, including comments from

1 Section 215(d)(2) of the Federal Power Act; 16 U.S.C. § 824(d)(2) (2018).

2 The NERC *Standard Processes Manual* is available at https://www.nerc.com/FilingsOrders/us/RuleOfProcedureDL/SPM_Clean_Mar2019.pdf.

3 NERC, *Minutes – Standards Committee Meeting* (June 14, 2017), Agenda Item 7, https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/Standards%20Committee%20Meeting%20Minutes%20-%20Approved_June_14_2017.pdf.

approximately 68 different people from approximately 50 companies, representing all 10 industry segments.[4]

In order to balance the experience and technical expertise on the SDT, the Standards Committee authorized a supplemental nomination period to consider additional candidates.[5] The second SDT nomination period was open from July 27, 2017 through August 9, 2017.

A second Standard Authorization Request was submitted by Northwest Power Pool Frequency Response Sharing Group recommending that the project add a second phase to address additional issues. The second SAR was posted for a 30-day formal comment period from November 2, 2017 through December 1, 2017. The second SAR received 42 sets of responses, including comments from approximately 115 different individuals and approximately 75 companies, representing all 10 industry segments.[6]

The project was thereafter broken out into two phases. The purpose of the first phase was to implement the recommendations of the 2016 Frequency Response Annual Analysis report to address Interconnection Frequency Response Obligation ("IFRO") calculation issues, primarily though targeted revisions to BAL-003-1.1 Attachment A and the supporting documents. The purpose of the ongoing second phase is to address broader potential revisions to BAL-003 requirements, including consideration of the IFRO method in its entirety and revisions to the applicable entities.

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4 *Comment Report – 2017-01 Modifications to BAL-003-1.1 SAR*, https://www.nerc.com/pa/Stand/Project201701ModificationstoBAL00311/2017-01_SAR_Comments_Raw_071917.pdf.

5 NERC, *Minutes – Standards Committee* Meeting (July 19, 2017), Agenda Item 12a (originally 2e), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/Standards%20Committee%20Meeting%20Minutes%20-%20Approved_July_19_2017.pdf.

6 NERC, *Consideration of Comments – 2017-01 Modifications to BAL-003-1.1* (April, 2018), https://www.nerc.com/pa/Stand/Project201701ModificationstoBAL00311/2017_01_NWPP_SAR_Comment_Response_April_2018.pdf.

Finally, on March 14, 2018 the Standards Committee authorized a final supplemental nomination period for additional members of the project 2017-01 SDT, particularly to add members from the generation industry segment.[7] Additional SDT nominations were open from March 19, 2018 through March 28, 2018. On April 18, 2018, the Standards Committee authorized including four additional nominees on the SDT and the combined SAR was accepted and posted, authorizing the project to move forward.[8]

B. First Posting – Informal Comment Period

An initial draft of proposed Reliability Standard BAL-003-2, Proposed Resource Loss Protection Criteria was posted for a 15-day informal comment period from September 6, 2018 through September 20, 2018, along with the revised *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*, revised FRS Form 1, and other supporting documents. There were 18 sets of responses, including comments from approximately 78 different individuals and approximately 56 companies, representing all 10 industry segments.[9]

C. Second Posting – Comment Period, Initial Ballot, and Non-binding Poll

On November 14, 2018, the Standards Committee authorized posting proposed Reliability Standard BAL-003-2 and the associated Implementation Plan, VRFs, and VSLs for a 45-day formal comment period and initial ballot, with a parallel additional ballot and non-binding poll

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[7] NERC, *Minutes – Standards Committee Meeting* (March 14, 2018), Agenda Item 6, https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/Standards%20Committee%20Meeting%20Minutes_Approved_April_18_2018.pdf.

[8] NERC, *Minutes – Standards Committee Conference Call* (April 18, 2018), Agenda Item 4, https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/Standards%20Committee%20Meeting%20Minutes%20-%20Approved%20June%2013,%202018.pdf.

[9] NERC, *Consideration of Comments – 2017-01 Modifications to BAL-003-1.1* (November 2018), https://www.nerc.com/pa/Stand/Project201701ModificationstoBAL00311/2017-01_Responses_to_Consideration%20of%20Comments_lka.pdf.

held during the last 10 days of the comment period.[10] The documents were posted for a 45-day formal comment period from December 4, 2018 through January 17, 2019, with a parallel additional ballot and non-binding poll held during the last 10 days of the comment period from January 8, 2019 through January 17, 2019.

The initial ballot for proposed BAL-003-2 received 96.41 percent approval, reaching quorum at 92.02 percent of the ballot pool. The Implementation Plan received 99.04 percent approval, reaching quorum at 91 percent of the ballot pool. The non-binding poll for the associated VRFs and VSLs received 93.89 percent supportive opinions, reaching quorum at 90.69 percent of the ballot pool. There were 23 sets of responses, including comments from approximately 93 different individuals and approximately 69 companies, representing all 10 industry segments.[11]

D. Final Ballot

Proposed Reliability Standard BAL-003-2 was posted for a 14-day final ballot period from October 10, 2019 through October 24, 2019. The ballot period was extended to allow stakeholders additional time to review updated versions of the VRFs and VSLs.[12] The ballot reached quorum at 92.96 percent of the ballot pool, with 100 percent approval.

E. Board of Trustees Adoption

On November 5, 2019, the NERC Board of Trustees adopted proposed Reliability Standard BAL-003-2, the Implementation Plan, and the associated VRFs and VSLs. The Board also adopted the revised *Procedure for ERO Support of Frequency Response and Frequency Bias Setting*

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[10] NERC, *Minutes – Standards Committee Conference Call* (November 14, 2018), Agenda Item 4, https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/Standards%20Committee%20Meeting%20Minutes%20-%20Approved%20December%2012,%202018.pdf.

[11] NERC, *Consideration of Comments – 2017-01 Modifications to BAL-003-1.1* (October 2019), https://www.nerc.com/pa/Stand/Project201701ModificationstoBAL00311/Project_2017-01_Consideration%20of%20Comments_lka.pdf.

[12] *Updated Standards Announcement – Project 2017-01 Modifications to BAL-003-1.1* (October 2019), https://www.nerc.com/pa/Stand/Project201701ModificationstoBAL00311/Project%202017-01%20Final_Ballot_Word_Announcement_update.pdf.

Standard. These actions officially concluded work under the first phase of Project 2017-01.[13] Work under the multi-year second phase of the project remains ongoing.

F. Errata Correction

On December 18, 2019, the Standards Committee approved errata to proposed Reliability Standard BAL-003-2; specifically, two corrections to Attachment A to the standard.[14]

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13 NERC, *Minutes – Board of Trustees* (November 5, 2019), Agenda Item 5b, at 5-6, https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/FINAL-Minutes-BOARD-Open-Meeting-Nov-2019.pdf.

14 *See* NERC Standards Committee Agenda Package, Agenda Item 8 (BAL-003-2 Errata) available at https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC%20Agenda%20Package_December182019.pdf.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Complete Record of Development

Project 2017-01 Modifications to BAL-003-1.1

Related Files

Status

A 10-day final ballot for **BAL-003-2 – Frequency Response and Frequency Bias Setting** concluded at **8:00 p.m. Eastern, Thursday, October 24, 2019**.

Background

Two Standard Authorization Requests (SARs) were received for modifying BAL-003-1.1. The first SAR was submitted by the NERC Resource Subcommittee (NERC RS) and was posted for industry comment from June 19, 2017 through July 18, 2017. The second SAR was submitted by the Northwest Power Pool Frequency Response Sharing Group (NWPP FRSG). This SAR proposes a two-phase approach to modifying the current standard.

The supporting documents for BAL-003-1 were developed using engineering judgment on the data collection and process needed to determine the Interconnection Frequency Response Obligation (IFRO) as well as the processing of raw data to determine compliance. Now that the standard is in place and the data is available for analysis, minor errors in assumptions as well as process inefficiencies have been identified. It was anticipated that as frequency response improves, the approaches embedded in the standard for annual samples may need to be modified. In addition to fixing the inconsistencies identified in the Frequency Response Annual Analysis Report, the drafting team may separate the administrative and procedural items and reassign them to an alternative process subject to ERO and NERC Operating Committee approval.

Standard(s) Affected: BAL-003-1 Frequency Response and Frequency Bias Setting | BAL-003-1.1 Frequency Response and Frequency Bias Setting

Purpose/Industry Need

The Phase I portion of the project proposes to revise the BAL-003-1 standard and process documents to address: (1) the inconsistencies in calculation of IFROs due to interconnection Frequency Response performance changes of Point C and/or Value B; (2) the Eastern Interconnection Resource Contingency Protection Criteria; (3) the frequency of nadir point limitations (currently limited to t0 to t+12); (4) clarification of language in Attachment A, i.e. related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities; and (5) the BAL-003-1 FRS Forms need enhancements that include, but may not be limited to, the ability to collect and submit FRSG performance data. Additionally, the supporting procedural and process steps may be removed from Attachment A and captured in an ERO and NERC Operating Committee approved Reference Document such that timely process improvements can be made as future lessons are learned.

This project will be a two-phase approach. The first phase will address the Phase 1 recommendations in the SAR. The scope of the work identified in the second phase will be to (1) establish a real-time reliability standard addressing the necessary frequency response to maintain reliability; (2) establish comparability for the correct responsible entity; (3) develop real-time measurements incorporating topology difference, and (4) eliminate the incorrect indicators.

The second phase will address the Phase II recommendations in the SAR: Make the Interconnection Frequency Response Obligation (IFRO) calculations and associated allocations: 1) more reflective of current conditions; 2) consider all characteristics affecting Frequency Response (e.g., load response, mix and type of generation); 3) include all applicable entities; and 4) be as equitable as possible; and

Frequency Response Measure (FRM): 1) ensure that over-performance by one entity does not negatively impact the evaluation of performance by another; 2) measure types/periods of response in addition to secondary Frequency Response, particularly primary Frequency Response; 3) include all applicable entities; and 4) make allocations as equitable as possible.

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft **BAL-003-2** Clean **(46)** | Redline to Last Posted **(47)** Redline to Last Approved **(48)** ***updated** **Implementation Plan** Clean **(49)** | Redline to Last Posted **(50)** **Supporting Materials** **VRF/VSL Justifications *updated** Clean **(51)** | Redline to Last Posted **(52)** Background Document **(53)** **Resources Loss Protection Criteria** Clean **(54)** | Redline to Last Posted **(55)** **Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard** Clean **(56)** | Redline to Last Posted **(57)** Redline to Last Approved **(58)** Revised FRS Form 1 **(59)** Modifications to FRS Form 1 **(60)**	**Final Ballot** Updated Info **(61)** Info **(62)** Vote	10/10/19 – 10/24/19 The ballot was extended to provide stakeholders adequate me to review the updated documents.	Ballot Results BAL-003-2 **(63)**	
Phase II Survey Form (Word)	Comment Period Info Submit Feedback	4/4/19 - 4/17/19		
Draft 1 **BAL-003-2** Clean **(27)** | Redline to Last Posted **(28)** Implementation Plan **(29)** **Supporting Materials** Unofficial Comment Form (Word) **(30)**	Initial Ballot Info **(39)** Vote	01/08/19 - 01/17/19	Ballot Results BAL-003-2 **(40)**	

VRF/VSL Justifications **(31)** Background Document **(32)** **Resources Loss Protection Criteria** Clean **(33)** | Redline to Last Posted **(34)** **Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard** Clean **(35)** | Redline to Last Posted **(36)** Revised FRS Form 1 **(37)** Modifications to FRS Form 1 **(38)** **Draft Reliability Standard Audit Worksheet (RSAW)**			Implementation Plan **(41)** Non-binding Poll Results BAL-003-2 **(42)**	Consideration of Comments **(45)**
	Comment Period Info **(43)** Submit Comments	12/04/18 - 01/17/19	Comments Received **(44)**	
	Join Ballot Pools	12/04/18 - 01/02/19		
	Info Send RSAW feedback to: RSAWfeedback@nerc.net	Coming Soon		
BAL-003-2 Redline **(19)** **Supporting Materials** Resources Loss Protection Criteria **(20)** Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard **(21)** Revised FRS Form 1 **(22)** Unofficial Comment Form (Word) **(23)**	Comment Period Info **(24)** Submit Comments	09/06/18 - 09/20/18	Comments Received **(25)**	Consideration of Comments **(26)**
Standard Authorization Request Clean **(17)** | Redline **(18)**	Approved by the Standards Committee	04/18/18		
Supplemental Drafting Team Nominations **Supporting Materials** Unofficial Nomination Form (Word) **(15)**	Supplemental Nomination Period Info **(16)** Submit Nominations	03/19/18 – 03/28/18		
Standards Authorization Request **(9)** (submitted by NWPP FRSG) **Supporting Materials** BAL-003 Technical Document Unofficial **(10)** Comment Form (Word) **(11)**	Comment Period Info **(12)** Submit Comments	11/02/17 - 12/01/17	Comments Received **(13)**	Consideration of Comments **(14)**

Supplemental Standard Authorization Request Team Nominations **Supporting Materials** Unofficial Nomination Form (Word) **(7)**	Supplemental Nomination Period Info **(8)** Submit Nominations	07/27/17 – 08/09/17		
Standards Authorization Request **(3)** (submitted by NERC RS) **Supporting Materials** Unofficial Comment Form (Word) **(4)**	Comment Period Info **(5)** Submit Comments	06/19/17 - 07/18/17	Comments Received **(6)**	
Standard Authorization Request Drafting Team Nominations **Supporting Materials** Unofficial Nomination Form (Word) **(1)**	Nomination Period Info **(2)** Submit Nominations	06/19/17 - 07/03/17		

Unofficial Nomination Form

Project 2017-01 Modifications to BAL-003-1.1 Drafting Team

Do not use this form for submitting nominations. Use the electronic form to submit nominations by **8 p.m. Eastern, Monday, July 3, 2017.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Additional information about this project is available on the Project 2017-01 Modifications to BAL-003-1.1 page. If you have questions, contact Senior Standards Developer Darrel Richardson, (via email), or at (609) 613-1848.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

Previous drafting or review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below.

Project 2017-01 Modifications to BAL-003-1.1

The purpose of this project is to review the issues identified in the SAR and make corresponding modifications to BAL-003-1.1 as necessary.

Standards affected: BAL-003-1 and BAL-003-1.1

The supporting documents for BAL-003-1.1 were developed using engineering judgment on the data collection and process needed to determine the Interconnection Frequency Response Obligation (IFRO) as well as the processing of raw data to determine compliance. Now that the standard is in place and the data is available for analysis, minor errors in assumptions as well as process inefficiencies have been identified. It was anticipated that as frequency response improves, the approaches embedded in the standard for annual samples may need to be modified. In addition to fixing the inconsistencies identified in the Frequency Response Annual Analysis Report (FRAA), the drafting team may separate the administrative and procedural items and reassign them to an alternative process subject to ERO and NERC Operating Committee approval.

The time commitment for these projects is expected to be up to two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed-upon timeline the review or drafting team sets forth. Team members may also have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the review and drafting team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

We are seeking a cross section of the industry to participate on the team, but in particular are seeking individuals who have experience and expertise in one or more of the following areas: Reliability

Coordinator operations, transmission operations, Balancing Authority operations and generation operations. Experience with developing standards inside or outside (e.g., IEEE, NAESB, ANSI, etc.) of the NERC process is beneficial, but is not required, and should be highlighted in the information submitted, if applicable.

Individuals who have facilitation skills and experience and/or legal or technical writing backgrounds are also strongly desired. Please include this in the description of qualifications as applicable.

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	
Please briefly describe your experience and qualifications to serve on the requested Standard Drafting Team (Bio):	
If you are currently a member of any NERC drafting team, please list each team here: ☐ Not currently on any active SAR or standard drafting team. ☐ Currently a member of the following SAR or standard drafting team(s):	
If you previously worked on any NERC drafting team please identify the team(s): ☐ No prior NERC SAR or standard drafting team. ☐ Prior experience on the following team(s):	

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:

☐ Texas RE	☐ NPCC	☐ SPP RE
☐ FRCC	☐ RF	☐ WECC
☐ MRO	☐ SERC	☐ NA – Not Applicable

Select each Industry Segment that you represent:	
☐	1 — Transmission Owners
☐	2 — RTOs, ISOs
☐	3 — Load-serving Entities
☐	4 — Transmission-dependent Utilities
☐	5 — Electric Generators
☐	6 — Electricity Brokers, Aggregators, and Marketers
☐	7 — Large Electricity End Users
☐	8 — Small Electricity End Users
☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:	
☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

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

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	
Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

Standards Announcement

Project 2017-01 Modifications to BAL-003-1.1

Drafting Team Nomination Period Open through July 3, 2017

Now Available

Nominations are being sought for members of the Project 2017-01 Modifications to BAL-003-1.1 standard drafting team (SDT) through **8 p.m. Eastern, Monday, July 3, 2017**.

Use the electronic form to submit a nomination. If you experience any difficulties using the electronic form, contact Nasheema Santos. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

The time commitment for this project is expected to be two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed upon timeline the team sets forth. Team members may also have side projects, either individually or by sub-group, to present for discussion and review. Lastly, an important component of the SDT effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful ballot.

Previous SDT experience is beneficial but not required. See the project page and nomination form for additional information.

Next Steps

NERC staff will present nominations to the Standards Committee in July 2017. Nominees will be notified shortly after the appointments have been made.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower

Atlanta, GA 30326
404-446-2560 | www.nerc.com

Standards Authorization Request Form

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

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

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	BAL-003-2 – Frequency Response and Frequency Bias Setting		
Date Submitted:			
SAR Requester Information			
Name:	Troy Blalock – Chair of the NERC Resource Subcommittee		
Organization:	NERC Resource Subcommittee		
Telephone:	803.217.2040	Email:	Jblalock@scana.com
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of Existing Standard	
☒ Revision to Existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The supporting documents for BAL-003-1.1 were developed using engineering judgment on the data collection and process needed to determine the Interconnection Frequency Response Obligation (IFRO) as well as the processing of raw data to determine compliance. Now that the standard is in place and the data is available for analysis, minor errors in assumptions as well as process inefficiencies have been identified. It is expected that as frequency response improves, the approaches embedded in the standard for annual samples may need to be modified. In addition to fixing the inconsistencies outlined below, the drafting team may separate the administrative and procedural items and reassign them to an alternative process subject to ERO and NERC Operating Committee approval. The items that need to be addressed are:

SAR Information
1. The IFRO calculation in BAL-003-1.1 needs to be revised due to inconsistencies identified in the 2016 Frequency Response Annual Analysis (FRAA) such as the IFRO values with respect to Point C and varying Value B. 2. Reevaluate the Eastern Interconnection Resource Contingency Protection Criteria. 3. Reevaluate the frequency nadir point limitations (currently limited to t_0 to t+12) 4. Clarification of language in Attachment A, i.e. related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities. 5. The BAL-003-1.1 FRS Forms need enhancements that include, but may not be limited to, the ability to collect and submit FRSG performance data.
Purpose or Goal (How does this request propose to address the problem described above?):
Revise the BAL-003-1.1 standard and process documents to address: (1) the inconsistencies in calculation of IFROs due to interconnection Frequency Response performance changes of Point C and/or Value B; (2) the Eastern Interconnection Resource Contingency Protection Criteria; (3) the frequency nadir point limitations (currently limited to t_0 to t+12), (4) clarification of language in Attachment A, i.e. related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities, (5) the BAL-003-1.1 FRS Forms need enhancements that include, but may not be limited to, the ability to collect and submit FRSG performance data. Additionally, the supporting procedural and process steps may be removed from Attachment A and captured in an ERO and NERC Operating Committee approved Reference Document such that timely process improvements can be made as future lessons are learned. For additional information on items #1, 2 and 3, please refer to the 2016 FRAA Report.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
1. The IFRO calculation in BAL-003-1.1 needs to be revised due to inconsistencies identified in the 2016 Frequency Response Annual Analysis (FRAA) such as the IFRO values with respect to Point C and varying Value B. 2. Reevaluate the Eastern Interconnection Resource Contingency Protection Criteria. 3. Reevaluate the frequency nadir point limitations (currently limited to t_0 to t+12) 4. Clarification of language in Attachment A, i.e. related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities. 5. The BAL-003-1.1 FRS Forms need enhancements that include, but may not be limited to, the ability to collect and submit FRSG performance data.

SAR Information
Brief Description (Provide a paragraph that describes the scope of this standard action.)
During the 2016 annual evaluation of the values used in the calculation of the IFRO the above mentioned issues were identified. The scope of the work will be to (1) address the inconsistency in the ratio of Point C to Value B, (2) reevaluate the Resource Contingency Protection Criteria for each interconnection, (3) reevaluate the frequency nadir point limitations (currently limited to t_0 to t+12), and (4) clarify language in Attachment A; (5) The BAL-003-1.1 FRS Forms need enhancements that include, but may not be limited to, the ability to collect and submit FRSG performance data and identify opportunities to make current processes more efficient. For additional information on items #1, 2 and 3, please refer to the 2016 FRAA Report.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Consider revising the BAL-003-1.1 standard concerning #1 above through the standards development process to correct the inconsistency in the ratio of Point C to Value B. This ratio in the IFRO calculation couples Point C and Value B together, resulting in IFRO trends that do not align with the intent of the standard. Improvement in Value B with no change in Point C (improving recovery phase) would result in higher obligations to be carried, essentially penalizing improved performance. Consider revising the BAL-003-1.1 standard concerning #2 above through the standards development process to modify the Resource Contingency Protection Criteria (RCPC). The RCPC for each interconnection should be revised to help ensure sufficient primary frequency response is maintained. The Eastern Interconnection uses the "largest resource event in last 10 years", which is the August 4, 2007 event. The standard drafting team should revisit this issue for modifications to BAL-003-1.1 standard, and the Resources Subcommittee should recommend how the events are selected for each interconnection. Consider revising the BAL-003-1.1 standard concerning #3 above through the standards development process to revisit the frequency nadir point used in the calculation. Many events, particularly in the Eastern Interconnection due to its large synchronous inertia, tend to have a frequency nadir point that exceeds the t_0 +12 seconds specified in BAL-003-1.1. Therefore, some events are characterized with a Point C value that is only partially down the arresting period of the event and does not accurately reflect the actual nadir. BAL-003-1.1 should be modified to allow for accurate representation of the Point C nadir value if exceeding beyond t_0+12 seconds. The actual event nadir can occur at any time, including

SAR Information
beyond the time period used for calculating Value B (t_0+20 through t_0+52 seconds), and may be the value known as Point C' which typically occurs in the 72 to 95 second range after t_0. Consider revising BAL-003-1.1 Attachment A to provide clarity of intent giving particular attention to FRSGs and the timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities. Consider transferring supporting procedural and process steps from Attachment A into an ERO and NERC Operating Committee approved Reference Document or Reliability Guideline. Consider revising the BAL-003-1.1 standard concerning #4 above through the standards development process to provide enhancements of the FRS Forms that include, but may not be limited to, the ability to collect and submit FRSG performance data.

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

Reliability Functions		
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the end-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the end-use customer.

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

Reliability and Market Interface Principles	
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

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

Related Standards	
Standard No.	Explanation
None	

Related SARs	
SAR ID	Explanation
None	

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	None.
FRCC	None.
MRO	None.
NPCC	None.
RFC	None.
SERC	None.
SPP	None.
WECC	None.

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template

Unofficial Comment Form

Project 2017-01 Modifications to BAL-003-1.1

Do not use this form for submitting comments. Use the electronic form to submit comments on the **Project 2017-01 Modifications to BAL-003-1.1** project. The electronic form must be submitted by **8 p.m. Eastern, Tuesday, July 18, 2017**.

Documents and information about this project are available on the Project 2017-01 Modifications to BAL-003-1.1 page. If you have questions, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

Background

The supporting documents for BAL-003-1.1 were developed using engineering judgment on the data collection and process needed to determine the Interconnection Frequency Response Obligation (IFRO) as well as the processing of raw data to determine compliance. Now that the standard is in place and the data is available for analysis, minor errors in assumptions as well as process inefficiencies have been identified. It was anticipated that as frequency response improves, the approaches embedded in the standard for annual samples may need to be modified. In addition to fixing the inconsistencies identified in the Frequency Response Annual Analysis Report (FRAA), the drafting team may separate the administrative and procedural items and reassign them to an alternative process subject to ERO and NERC Operating Committee approval.

Please provide your responses to the questions listed below along with any detailed comments.

Questions

1. The SAR discusses revising BAL-003-1.1 standard concerning the ratio of Point C to Value B to correct the inconsistency in the ratio identified in the FRAA report. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

   ☐ Yes
   ☐ No

   Comments:

2. The SAR discusses revising the BAL-003-1.1 standard concerning modifying the Resource Contingency Protection Criteria (RCPC) to help ensure sufficient primary frequency response is maintained. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

   ☐ Yes
   ☐ No

   Comments:

3. The SAR proposes to review and modify as necessary Attachment A of the standard to remove administrative tasks and provide additional clarity. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

   ☐ Yes
   ☐ No

   Comments:

4. The SAR proposes to modify the FRS Forms to allow for collection and submission of performance data for Frequency Response Sharing Groups. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

   ☐ Yes
   ☐ No

   Comments:

5. Based on the scope of the SAR, do you have any other comments for drafting team consideration?

☐ Yes
☐ No

Comments:

Standards Announcement

Project 2017-01 Modifications to BAL-003-1.1
Standards Authorization Request

Formal Comment Period Open through July 18, 2017

Now Available

A 30-day formal comment period for the **Project 2017-01 Modifications to BAL-003-1.1** Standards Authorization Request (SAR), is open through **8 p.m. Eastern, Tuesday, July 18, 2017**.

Commenting

Use the electronic form to submit comments on the SAR. If you experience any difficulties using the electronic form, contact Nasheema Santos. An unofficial Word version of the comment form is posted on the project page.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The drafting team will review all responses received during the comment period and determine the next steps of the project.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email), or at (609) 613-1848.

Atlanta, GA 30326
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Comment Report

Project Name:	2017-01 Modifications to BAL-003-1.1 SAR
Comment Period Start Date:	6/19/2017
Comment Period End Date:	7/18/2017
Associated Ballots:	

There were 17 sets of responses, including comments from approximately 68 different people from approximately 50 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The SAR discusses revising BAL-003-1.1 standard concerning the ratio of Point C to Value B to correct the inconsistency in the ratio identified in the FRAA report. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

2. The SAR discusses revising the BAL-003-1.1 standard concerning modifying the Resource Contingency Protection Criteria (RCPC) to help ensure sufficient primary frequency response is maintained. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

3. The SAR proposes to review and modify as necessary Attachment A of the standard to remove administrative tasks and provide additional clarity. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

4. The SAR proposes to modify the FRS Forms to allow for collection and submission of performance data for Frequency Response Sharing Groups. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

5. Based on the scope of the SAR, do you have any other comments for drafting team consideration?

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Karl Kohlrus	Prairie Power, Inc.	1,3	SERC
					Mark Ringhausen	Old Dominion Electric Cooperative	3,4	SERC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Electric Reliability Council of Texas, Inc.	Elizabeth Axson	2		IRC Standards Review Committee	Elizabeth Axson	ERCOT	2	Texas RE
					Ben Li	IESO	2	NPCC
					Mark Holman	PJM	2	RF
					Greg Campoli	NYISO	2	NPCC
					Terry BIlke	Midcontinent ISO, Inc.	2	MRO
					Ali Miremadi	California ISO	2	WECC
					Matthew Goldberg	ISO NE	2	NPCC
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	SPP RE
Southern Company - Southern Company	Marsha Morgan	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc	1	SERC
					Jennifer Sykes	Southern	6	SERC

Services, Inc.						Company Generation and Energy Marketing		
					R Scott Moore	Alabama Power Company	3	SERC
					William Shultz	Southern Company Generation	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC

					Michael Forte	Con Edison	1	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Greg Campoli	NYISO	2	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Scott Aclin	Southwest Power Pool Inc.	2	SPP RE
					Margaret Adams	Southwest Power Pool Inc.	2	SPP RE
					Daniel Baker	Southwest Power Pool Inc.	2	SPP RE

1. The SAR discusses revising BAL-003-1.1 standard concerning the ratio of Point C to Value B to correct the inconsistency in the ratio identified in the FRAA report. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	Yes
Document Name	

Comment

Southern agrees with correcting the inconsistency.

Likes 0	
Dislikes 0	

Response

Joshua Eason - ISO New England, Inc. - 2 - NPCC

Answer	Yes
Document Name	

Comment

Table 1 in Attachment A is good demonstration of how IFRO is calculated, but some statistically determined data in the table may appear out-of-date for years when frequency response is improving. Ideally, the parameters used to calculate the current IFRO should be updated to accurately reflect the general trend in most recent years. If the goal is to shape Attachment 1 in such way that it will be modified as little as possible in the future, one feasible way is to let Table 1 just serve as a typical example of calculating IFRO while recording the latest parameters in a separate document, similar to how it is done for FRAA. With respect to the ratio of C-to-B ("CBR" or CB Ratio), it's necessary to update this key syntax according to the overall trend of recent system performance change, but it doesn't have to exactly line up with the ratio from the latest FRAA. The reason for this is that the ratio from each year's measurement may individually contain unexpected random factors that could eventually introduce an abrupt change to IFRO. Taking the performance of multiple recent years into consideration in determining the ratio can effectively smooth such impact. Additionally, ISO-NE believes that using the CBR: (1) does not accurately reflect that governor response has little to do with arresting frequency in the Eastern Interconnection, and (2) that the use of the current CBR provides a perverse incentive in that it essentially penalizes improved governor response.

Likes 0	
Dislikes 0	

Response

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer	Yes
Document Name	

Comment	
As a member of the NWPP Frequency Response Sharing Group, Idaho Power agrees with the proposed revision.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	
The IRC SRC has no comment.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
The SPP Standards Review Group recommends that the drafting team develop some proposed language that will provide more details or give a better understanding in reference to the component (CBR - which is the statistically determined ratio of the Point C to Value B) mentioned in Attachment A. Also, we recommend that the drafting team mention a reference document that contains the IFRO calculation for informational purposes.	
Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1 - WECC	
Answer	Yes
Document Name	
Comment	

See comments in response to Question No. 5.

Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kasey Bohannon - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. The SAR discusses revising the BAL-003-1.1 standard concerning modifying the Resource Contingency Protection Criteria (RCPC) to help ensure sufficient primary frequency response is maintained. Do you agree with this proposed revision?   If not, please provide specific language on the proposed revision.

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment

The SAR only identifies that changes to the BAL-003-1.1 standard an Eastern Interconnection Resource Contingency Protection Criteria (RCPC). In the 2016 Frequency Response Annual Analysis Report, NERC identifies that the RCPC of all Interconnections should be revised to help ensure sufficient primary frequency response is maintained. We believe this should be clarified in the purpose and objectives of the SAR.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	No
Document Name	

Comment

The SPP Standards Review Group recommends that the drafting team develop some proposed language that will provide more details or give a better understanding in reference to the component (RCPC) in Attachment A and how the RCC component is associated as well. Also, we recommend that the drafting team provides clarity on how they intend to address the potential changes of the RCC component and what impacts it will have on the industry.

Likes 0	
Dislikes 0	

Response

Dori Quam - NorthWestern Energy - 1 - WECC

Answer	Yes
Document Name	

Comment

NorthWestern Energy supports modifying the RCPC for each Interconnection to ensure sufficient primary frequency response is maintained. However, rather than the Resources Subcommittee recommending how events are selected for each Interconnection, the appropriate group in each Interconnection should determine the criteria for its own Interconnection. In addition, see comments in response to Question No. 5.

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee

Answer	Yes
Document Name	

Comment

The IRC SRC has no comment. SPP does not join this response.

Likes 0	
Dislikes 0	

Response

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer	Yes
Document Name	

Comment

As a member of the NWPP Frequency Response Sharing Group, Idaho Power agrees with the proposed revision.

Likes 0	
Dislikes 0	

Response

Joshua Eason - ISO New England, Inc. - 2 - NPCC

Answer	Yes
Document Name	

Comment

After the proposed revision is made, the same RCC that is currently used in the Eastern Interconnection should continue to be used after August 3, 2017. Strictly following the current RCPC without any change would impose a substantial change in the RCC after August 3, 2017 which would

drastically impact the IFRO of the Eastern Interconnection. Such sudden change in the IFRO is not desirable, particularly when primary frequency response continues to consistently improve. If the latest system condition implies a scenario where the current RCC used in the Eastern Interconnection appears to no longer be valid, then the new criteria used to establish the RCC must be one that results in minimal impact to IFRO.

Likes 0	
Dislikes 0	
Response	

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern agrees with the proposed change and method of change.	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kasey Bohannon - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. The SAR proposes to review and modify as necessary Attachment A of the standard to remove administrative tasks and provide additional clarity. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE is concerned process and timeline specifications in a supplemental document would not be enforceable. Texas RE strongly encourages the SDT to closely evaluate which steps are being moved to ensure they are purely administrative and not reliability tasks that are essential for the reliable operation of the Bulk Electric System (BES).	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SPP Standard Review Group recommends that the drafting team develop some proposed language explaining why they recommend the removal of any supporting procedural and process steps from the Attachment A in the standard and transferring this information to a Reliability Guideline. Additionally, we recommend that the proposed language clearly states that once the information is removed from the standard and placed into a guideline, this information can no longer be considered to have compliance/audit implications.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
The authors of the SAR failed to uniformly incorporate the relocation of the standard's Attachment A to a NERC Operating Committee-approved Reference Document or Reliability Guideline. The relocation of Attachment A should be identified upfront in the purpose and objectives of the SAR. We believe Attachment A should be relocated, as its contents identify calculated values that should be periodically reevaluated outside the Standards	

Development Process.	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern agrees this allows flexibility to correct the process in the future.	
Likes 0	
Dislikes 0	
Response	
Joshua Eason - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
In Attachment A, the Frequency Response Measure section can be made more concise by including only the necessary information such as the basic description of the measurement methodology, the definition of timeframes associated with A, B, and C values, and the typical data sources for measurement. Other details could be removed from the current version of Attachment A to be incorporated to the instruction portion of Forms 1 and 2 or a separate document such as the user manual for Forms 1 and 2 where more detailed instructions and "what if" examples could be added. Preferably, the section on the Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities should be retained and remain in Attachment A, because the timelines are important to keep in mind and there's no better place for them.	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	

As a member of the NWPP Frequency Response Sharing Group, Idaho Power agrees with the proposed revision.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	Yes
Document Name	
Comment	
The IRC SRC has no comment. SPP does not join this response.	
Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1 - WECC	
Answer	Yes
Document Name	
Comment	
NorthWestern agrees with revising Attachment A; however, NorthWestern believes any Reference Documents or Reliability Guidelines developed should be Interconnection specifi — i.e., *Consider transferring supporting procedural and process steps from Attachment A into an ERO and NERC Operating Committee approved **Interconnection-Specific** Reference Document or Reliability Guideline.* In addition, see comments in response to Question No. 5.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kasey Bohannon - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

4. The SAR proposes to modify the FRS Forms to allow for collection and submission of performance data for Frequency Response Sharing Groups. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

Dori Quam - NorthWestern Energy - 1 - WECC

Answer	Yes
Document Name	

Comment

See comments in response to Question No. 5.

Likes 0	
Dislikes 0	

Response

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee

Answer	Yes
Document Name	

Comment

The IRC SRC has no comment.

Likes 0	
Dislikes 0	

Response

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer	Yes
Document Name	

Comment

As a member of the NWPP Frequency Response Sharing Group, Idaho Power agrees with the proposed revision.

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern agrees the RS needs the ability to ensure that RSG's are performing.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kasey Bohannon - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua Eason - ISO New England, Inc. - 2 - NPCC	
Answer	
Document Name	
Comment	
ISO-NE believes that each FRSG should be treated as one whole entity (*i.e*. as though it were an intact BA that neglects internal connections) in collection and submission of performance data. This will allow the FRSG to be judged for compliance as a single collective, which is the presumed intent of a Frequency Response Sharing Group.	
Likes 0	
Dislikes 0	
Response	

5. Based on the scope of the SAR, do you have any other comments for drafting team consideration?	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
No other comments at this time.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2, Group Name IRC Standards Review Committee	
Answer	No
Document Name	
Comment	
The IRC SRC has no comment.	
Likes 0	
Dislikes 0	
Response	
John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua Eason - ISO New England, Inc. - 2 - NPCC	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
BPA participated with 18 other Balancing Authorities to draft another SAR and technical support document for BAL-003, through the coordination of the Frequency Response Sharing Group (FRSG). If the FRSG SAR is approved, BPA requests that the two SARs are combined.	
Likes 1	NorthWestern Energy, 1, Quam Dori
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy agrees with the scope of the SAR, and agrees with the modifications as currently proposed.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE requests a link to the 2016 FRAA report be made available on the project page.	
Likes 0	
Dislikes 0	
Response	
Kasey Bohannon - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

AZPS appreciates and agrees that the language in Appendix A would greatly benefit from a thorough review and revision to make the information easier to understand. For example, we note that there is no description of where the Starting Frequency (FStart) for each Interconnection is derived. The current language claims that "detailed descriptions of the calculations used in Table 1…are defined in the *Procedure for ERO Support of Frequency Response and* Frequency Bias Setting Standard." But in actuality, they are not. Additionally, the last sentence of first paragraph of Attachment A (A maximum delta frequency (MDF) is calculated by adjusting a starting frequency) implies that the starting frequency is being adjusted where is it is the delta frequency which is being adjusted.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	Yes
Document Name	

Comment

(1) We caution that the scope identified within the SAR is too broad and appears to have no definite deadlines. The rush to address inconsistencies in the ratio of Point C to Value B, RCPC, and frequency nadir point limitations, as identified within the 2016 Frequency Response Annual Analysis Report, does not align with a similar deadline to introduce Attachment A and FRS Form enhancements. The latter clarifications could delay the standard development process unnecessarily. We believe the SAR should remove references to identify and incorporate all process modifications, and instead identify only enhancements to Attachment A and FRS Forms that are supportive of the 2016 Frequency Response Annual Analysis Report.

(2) We thank you for this opportunity to provide these comments.

Likes 0	
Dislikes 0	

Response

Dori Quam - NorthWestern Energy - 1 - WECC

Answer	Yes
Document Name	

Comment

NorthWestern Energy participated with 18 other Balancing Authorities to draft a SAR and technical support document for BAL-003, through the coordination of the Northwest Power Pool (NWPP) Frequency Response Sharing Group (FRSG). If the FRSG SAR is approved, NorthWestern Energy requests that the two SARs be combined. If the FRSG SAR is not approved, each Interconnection should be allowed to develop its own Frequency Response and Frequency Bias Setting Standard.

Likes 0	
Dislikes 0	

Response

Unofficial Nomination Form

Project 2017-01 Modifications to BAL-003-1.1 Standard Authorization Request Drafting Team

Do not use this form for submitting nominations. Use the electronic form to submit nominations by **8 p.m. Eastern, Wednesday, August 9, 2017.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Additional information about this project is available on the Project 2017-01 Modifications to BAL-003-1.1 page. If you have questions, contact Senior Standards Developer Darrel Richardson, (via email), or at (609) 613-1848.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

Previous drafting or review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below.

Project 2017-01 Modifications to BAL-003-1.1

The purpose of this project is to review the issues identified in the SAR and make corresponding modifications to BAL-003-1.1 as necessary.

Standards affected: BAL-003-1 and BAL-003-1.1

The supporting documents for BAL-003-1.1 were developed using engineering judgment on the data collection and process needed to determine the Interconnection Frequency Response Obligation (IFRO) as well as the processing of raw data to determine compliance. Now that the standard is in place and the data is available for analysis, minor errors in assumptions as well as process inefficiencies have been identified. It was anticipated that as frequency response improves, the approaches embedded in the standard for annual samples may need to be modified. In addition to fixing the inconsistencies identified in the Frequency Response Annual Analysis Report (FRAA), the drafting team may separate the administrative and procedural items and reassign them to an alternative process subject to ERO and NERC Operating Committee approval.

The time commitment for these projects is expected to be up to two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed-upon timeline the review or drafting team sets forth. Team members may also have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the review and drafting team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

We are seeking a cross section of the industry to participate on the team, but in particular are seeking individuals who have experience and expertise in one or more of the following areas: Reliability Coordinator operations, transmission operations, Balancing Authority operations and generation operations. Experience with developing standards inside or outside (e.g., IEEE, NAESB, ANSI, etc.) of the NERC process is beneficial, but is not required, and should be highlighted in the information submitted, if applicable.

Individuals who have facilitation skills and experience and/or legal or technical writing backgrounds are also strongly desired. Please include this in the description of qualifications as applicable.

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	

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

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

Select each Industry Segment that you represent:	
☐	1 — Transmission Owners
☐	2 — RTOs, ISOs
☐	3 — Load-serving Entities
☐	4 — Transmission-dependent Utilities
☐	5 — Electric Generators
☐	6 — Electricity Brokers, Aggregators, and Marketers
☐	7 — Large Electricity End Users
☐	8 — Small Electricity End Users
☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:	
☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

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

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	
Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization’s willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

Standards Announcement

Project 2017-01 Modifications to BAL-003-1.1

Supplemental Nomination Period Open through August 9, 2017

Now Available

Nominations are being sought for additional Standards Authorization Request drafting team members through **8 p.m. Eastern, Wednesday, August 9, 2017**. If you submitted a nomination during the initial nomination period, June 19, 2017 through July 3, 2017, you do not need to resubmit your nomination.

The nomination period is being reopened at the request of the NERC Standards Committee. There was considerable overlap in the nominations received for this project and Project 2017-06 Modifications to BAL-002-2. The Standards Committee requested the additional nomination period to 1) reduce the overlap between the two aforementioned projects; and, 2) increase the diversity within the two drafting teams.

Use the electronic form to submit a nomination. If you experience any difficulties using the electronic form, contact Nasheema Santos. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

Previous drafting or periodic review team experience is beneficial, but not required. See the project page and nomination form for additional information.

Next Steps

The Standards Committee is expected to appoint members to the team September 2017. Nominees will be notified shortly after they have been selected.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

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

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Authorization Request Form

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

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

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	BAL-003-1 – Frequency Response and Frequency Bias Setting		
Date Submitted: 2/17/2017			
SAR Requester Information			
Name:	Jerry Rust – Designated Representative For Frequency Response Sharing Group (18 BAs)		
Organization:	Frequency Response Sharing Group		
Telephone:	503.445.1074	Email:	jerry@nwpp.org
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of Existing Standard	
☒ Revision to Existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
There are several problems with respect to the existing Standard: • The IFRO calculation in BAL-003-1 needs to be revised due to inconsistencies identified in the 2016 Frequency Response Annual Analysis (FRAA) such as the IFRO values with respect to Point C and varying Value B, the Eastern Interconnection Resource Contingency Protection Criteria, evaluation of t_0 and clarification of language in the 2016 Frequency Response Annual Analysis (FRAA) Report.

SAR Information
• The IFRO calculation in BAL-003-1 is retrospect and has no bearing on real-time reliability • Allocation of the IFRO to the BAs has no reflection of real-time situation; it is predicated on two-year old information. • The applicability to the FRSG or a BA that is not part of an FRSG is not tied to any ability to provide response, since response is either from generator or load. The BA is responsible for balancing, frequency load response is inherient to load characteristics and non controllable unless load is shed. Generator response is controllable through proper governor operation thus there is direct applicability to Generator Owners and Operators. • The arbitrary allocation formula assumes all BAs have exactly the same characteristics, such as load response, mix and type of generation, and others, which is not true, and thus is not providing comparability across all BAs. • FRM is calculated using net interchange actual which assumes all BAs have exactly the same settings for response, where one large BA could have a governor and or speed controller setting with zero deadband and set to respond at twice their allocated requirement, that may result in the apparent suppressing of the adjacent BA's response, since measurement is interchange. In addition, BAL-003-1 appears to drive an arbitrary market and pricing, thus it is not market neutral. • The FRM measurement period (20-52 seconds) is too far beyond the event to accurately measure the frequency-response provided (10-20 seconds) to arrest the frequency deviation. FRM should be measured correctly and obligated to all the correct responsible parties within an Interconnection. • The intent of the Standard is to assure adequate Frequency Response for the Interconnection. The standard should address the adequate amount of Frequency Response to arrest sudden frequency deviations within an Interconnection. The standard must be able to measure all types of Frequency Response and credit the providers. The current standards doesnot reflect different types of Frequency Response and the timing of such response.
Purpose or Goal (How does this request propose to address the problem described above?):
Revise the BAL-003-1 standard in a two phase approach First phase address: • the inconsistencies in calculation of IFROs for Interconnection Frequency Response performance changes of Point C and/or Value B; • the Eastern Interconnection Resource Contingency Protection Criteria; • the evaluation of $t_{0;}$ and,

SAR Information
• clarification of language in Attachment A, i.e. related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities. Please refer to the 2016 FRAA Report for additional information. Second phase address: • Assign the ability to control and provide Frequency Response to the correct applicable entity; • Tie Frequency Response to real-time reliability; • Eliminate arbitrary and non-comparable formulas; • Establish a process to measure Frequency Response that is not an arbritrary estimate using NetActual Interchange; • Establish a process that reflects measurement of real-time reliability associate with frequency response; • Reflect real-time topology of BES and capability and variances in types of response; • Eliminate the incorrect signals to the market for arbritray pricing and conditions; and • Develop a more correct real-time reliability standard.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
For Phase 1, please refer to the 2016 Frequency Response Annual Analysis (FRAA) Report. For Phase 2, modify the standard reflecting real-time with the correct responsible entity identified.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
For Phase 1, during the 2016 annual evaluation of the values used in the calculation of the IFRO, the above mentioned problems were identified. The scope of the work will be to (1) address the inconsistency in the CBR ratio, (2) reevaluate the Resource Contingency Protection Criteria for each interconnection, (3) reevaluate the frequency nadir point limitations (currently limited to t_0 to t+12), and clarify language in the 2016 Frequency Response Annual Analysis (FRAA) Report. Please refer to the 2016 FRAA Report for additional information. For Phase 2, the FRSG has identified the above issues and the unintended consequences, without addressing real-time reliability. The scope of the work will be to (1) establish a real-time reliability standard addressing the necessary frequency response to maintain reliability, (2) establish

SAR Information
comparability for the correct responsible entity, (3) develop real-time measurements incorporating topology difference, and (4) eliminate the incorrect indicators.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
For Phase 1: • Consider revising the BAL-003-1 standard concerning #1 above through the standards development process to correct the inconsistency in the CBR ratio. The CBR ratio in the IFRO calculation couples Point C and Value B together, resulting in IFRO trends that do not align with the intent of the standard. Improvement in Value B with no change in Point C (improving recovery phase) would result in higher obligation to be carried, essentially penalizing improved performance. • Consider revising the BAL-003-1 standard concerning #2 above through the standards development process to modify the Resource Contingency Protection Criteria. The Resource Contingency Protection Criteria for each interconnection should be revised to help ensure sufficient primary frequency response is maintained. The Eastern Interconnection uses the “largest resource event in last 10 years”, which is the 4 August 2007 event. The standard drafting team should revisit this issue for modifications to BAL-003-1 standard, and the Resources Subcommittee should recommend how the events are selected for each interconnection. • Consider revising the BAL-003-1 standard concerning #3 above through the standards development process to revisit the frequency nadir point used in the calculation. Many events, particularly in the Eastern Interconnection due to its large synchronous inertia, tend to have a frequency nadir point that exceeds the t_0 +12 seconds specified in BAL-003-1. Therefore, some events are characterized with a Point C value that is only partially down the arresting period of the event and does not accurately reflect the actual nadir. BAL-003-1 should be modified to allow for accurate representation of the Point C nadir value if exceeding t_0+12 seconds. The actual event nadir can occur at any time, including beyond the time period used for calculating Value B (t_0+20 through t_0+52 seconds), and may be the value known as Point C’ which typically occurs from 72 to 95 seconds after t_0. • Consider revising BAL-003-1 Attachment A to provide clarity to the intent with particular attention to FRSGs and the timeline for Balancing Authority Frequency Response and Frequency Bias Setting. Please refer to the 2016 FRAA Report for additional information. For Phase 2:

SAR Information
• Consider revising BAL-003-1 standard to reflect real-time measurement of frequency performance vs. a two year old allocation. • Consider revising BAL-003-1 Standard to reflect the correct applicable entity that controls and provides frequency response. • Consider revising BAL-003-1 Standard to reflect comparability among the applicable entities. • Consider revising BAL-003-1 Standard to eliminate arbritray allocation of responsibility. • Consider revising BAL-003-1 Standard to eliminate the incorrect signals that have created unintended consequences.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.

Reliability Functions		
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the end-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the end-use customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☒	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

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

Related Standards	
Standard No.	Explanation
None	

Related SARs	
SAR ID	Explanation
None	

Related SARs	

Regional Variances	
Region	Explanation
ERCOT	None.
FRCC	None.
MRO	None.
NPCC	None.
RFC	None.
SERC	None.
SPP	None.
WECC	None.

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template

Standards Authorization Request
Revision to
BAL-003-1.1 Frequency Response and Frequency Bias Setting
June 28, 2017

The North American Electric Reliability Corporation (NERC*)* Standard Process Manual Version 3, Section 4.0, *Process for Developing, Modifying, Withdrawing or Retiring a Reliability Standard* requires a Standard Authorization Request (SAR) that proposes to substantially revise a Reliability Standard to be accompanied by a technical justification that includes, at a minimum, a discussion of the reliability-related benefits and costs of modifying the Reliability Standard and a technical foundation document to guide the development of the Reliability Standard. North America's only registered Frequency Response Sharing Group (FRSG), consisting of 20 Balancing Authority Areas (BAAs) within the Western Interconnection (encompassing 38 BAAs in total), submitted a SAR on February 17, 2017 requesting a revision to the existing Reliability Standard BAL-003-1.1 (BAL-003). NERC has requested additional technical justification for the SAR.

This document provides further technical justification for the previously submitted SAR, organized according to the following topics:

- Real-Time Reliability
- Event Selection
- Measurement
- Assumption behind the current standard
- Goal of a Reliability Standard

Real-Time Reliability

BAL-003 states that compliance is judged according to performance for the median event out of a larger set of historical events evaluated for a particular compliance year. This suggests it is acceptable for BAAs to provide adequate frequency response just over half the time. The standard assumes a statistical probability that if one BAA fails there will be enough excess response from other BAAs to compensate. But it also follows that all BAAs could simultaneously provide insufficient frequency response on multiple occasions without any compliance failures. This fact alone indicates BAL-003 does not adequately assure real-time reliability.

Furthermore, relying on historical event analysis to establish and evaluate frequency response does not ensure frequency response is available in real-time. Frequency response is needed 24 hours a day, 365 day a year, to manage interconnection frequency and recover from frequency events. If the Interconnection were dispatched as a single system, the operator would estimate frequency response capability needed from each resource and dispatch those resources as necessary to ensure reliability. An interconnection made up of multiple BAAs should not be treated any differently.

BAA operators must decide how to operate their systems to support reliability. BAL-003, in its current form, does not specify the amount of frequency response reserves needed in real-time for reliability—that is, capacity needed on frequency responsive resources to be prepared for the design event of an Interconnection Most Severe Single Contingency. Yet NERC's *Reliability Guideline for Operating Reserve Management* (*Guideline*) addresses this question directly. Section V.a. of the guideline states:

> *To determine an initial target (at scheduled frequency) frequency responsive reserve level (in MW) for a given responsible entity, simply multiply 10 times the responsible entity's FRO (because FRO is in MW/0.1 Hz) by the MDF for the responsible entity's Interconnection. An example to illustrate this:*
>
> *Given: ABC responsible entity is in the Eastern Interconnection (EI) and its pro-rata portion of IFRO is 1.5%.*
>
> *The key EI parameters from Table 1 are: IFRO = 1002 MW/0.1 Hz and MDF = 0.449 Hz.*
>
> *The responsible entity's FRO is {1.5% *1002 MW/0.1 Hz} or 15.2 MW/0.1 Hz.*
>
> *The responsible entity's initial frequency responsive reserve target is {10 * 15.2 * 0.449} or 67.48 MW.*
>
> *The initial target may need to be modified based on several factors, most of which are addressed later in this section. For example, if actual performance indicates additional response is needed, then the target should be increased.*

The studies performed by NERC determined the Maximum Delta Frequency A to B based on a statistical analysis of the B to C ratio. This study, in conjunction with the *Guideline*, indicates the Western Interconnection should maintain frequency responsive reserve capacity online at all times equal to approximately three times the Interconnection Frequency Response Obligation (IFRO). This amount is disputable and seems like an overestimate of reserve needed in the Western Interconnection. This is in light of The Western Interconnection's frequency response performance in recent events approximately the MW size of the double Palo-Verde design event. An overestimate or not, the current standard only obligates a BA to keep some level of this reserve available a little more than half of the year. BAL-003 must provide for this and more study needs to justify the reserves needed by BAs in real-time. Until then, the guideline provides some guidance for how much a BAA should hold in MW capacity, but the *Guideline* further states:

> *The responsible entity also may choose to perform a risk analysis in determining the level of frequency responsive reserve that assures compliance at an acceptable cost.*

This presents a problem. Reliability should not turn on economic decisions. Reliability requirements must be incorporated into standards and not just captured in guidelines that are enforced solely by peer pressure within industry. Instead of being clear, BAL-003 sends mixed messages to BAAs.

Given the current gap in BAL-003 and the "wiggle room" in the *Guideline*, BAAs could achieve compliance in many unreliable ways. For example, a BAA could only hold enough capacity to cover a 0.1 Hz deviation, because most BAL-003 measurement events in the Western Interconnection are less than 0.1 Hz (since evaluation of FRM as currently prescribed in BAL-003-1.1 began in compliance year 2015, the average frequency deviation of all NERC selected events was only -0.060 Hz/0.10 MW). Or, a BAA could plan to meet all events in two quarters of a compliance year, and then neglect the other two quarters. A pattern that could be desirable for entities that take down generation for annual maintenance, normally in the spring in the Western Interconnection. Even if BAAs operate conscientiously to protect reliability, BAL-003 creates confusion about what is needed in real-time to support reliability.

Following FERC's order approving BAL-003, markets have developed for "paper" transactions in which one BAA can agree with another to transfer "credit" for calculated frequency response (referred to as Frequency Response Transfers). While the members of FRSG generally support allowing BAAs to comply through Frequency Response Transfers, they worry that assessing compliance according to a median-based metric could degrade real-time reliability.

For example:

> Suppose a BAA cannot fully comply with BAL-003, but has existing generation equipment that does provide some frequency response. The BAA finds itself integrating substantial variable generation that does not provide automatic frequency response. The increasing variable generation displaces frequency-responsive generating units for at least half of the operating hours. The BAA weighs its options. It could pay generators to improve equipment; it could alter dispatch to increase headroom on frequency responsive units; it could install a battery capable of frequency response; and so on. After analysis, the BAA decides it is most economic to meet its Frequency Response Obligation (FRO) entirely through Frequency Response Transfers. The BAA does not seek to improve equipment capability, and it has every right to shut down frequency-responsive units to make room for the new variable generation. Available frequency response will decline compared to historic levels. The BAA now relies entirely on the transferring BAA. In this scenario, historic frequency response is lost. The transferring BAA need only respond adequately for more than half of the compliance measurement events, and the purchasing BAA is relieved of any obligation to provide frequency response in real-time. This also flies in the face of the underlying assumption of statistical probability.

BAL-003 does not require *operational* (as opposed to paper) transfers of frequency response, and therefore has not resulted in creation of real-time markets for frequency response. NERC regulations should drive market signals that reflect what is truly needed for reliability, and ensure 100% coverage through equipment, capacity, and dispatch.

Another problem with BAL-003 is that it measures the average frequency support in the 20 to 52 seconds following a frequency event, even though machine action is needed within the first 20 seconds to arrest rapid frequency decline in the Western Interconnection. The measurement lag encourages BAAs to delay response to improve compliance metrics, which subverts the primary purpose of the standard. Western Interconnection frequency could drop low enough to trigger Underfrequency Load Shedding without a single BAA failing to comply with BAL-003. This lessens, rather than enhances, Western Interconnection reliability.

The FRSG recognizes, as do NERC and FERC, that the generation fleet is changing. Frequency response will likely decline unless operators maintain frequency-responsive capability and resources are dispatched in real-time to provide adequate headroom for frequency response. The FRSG also concurs with NERC that, historically, the Western Interconnection has had sufficient frequency response. To speak plainly, the sky is not falling and risks to reliability may not be immediate. But neither NERC nor the electric utility industry should ignore this issue. Operational requirements must be clearly stated to ensure that equipment, operations, and markets develop to support real-time reliability now and in the future.

Event Selection and Measurement:

Several aspects of BAL-003's event selection and response measurement process may perversely reward poor performance and penalize proper performance. NERC's *Reliability Guideline on Primary Frequency Control* encourages Generator Operators to set governor dead bands of no more than 36 mHz (and recommends using an even smaller dead band), with a ramped (not stepped) droop of between 4% to 5%. While a smaller dead band may be feasible in the Eastern Interconnection, frequency within the smaller Western Interconnection is more variable. Here, smaller dead bands would impose undue burdens on thermal generators. Likewise, due to the size of the Western Interconnection, credible N-1 events can drop the C and B frequency points well outside the 36 mHz dead band.

In the Western Interconnection, the generation fleet provides primary frequency response for large events through governor action. Operators have gone to significant effort, in good faith, to tune governors and associated controls according to the *Guideline* to protect reliability and comply with BAL-003. Yet the current methods of event selection and response measurement do not take these settings into account.

One deficiency is that FRO and Frequency Response Measured (FRM) derive from change in frequency instead of actual frequency. Many governors have been set (as indicated by the *Guideline*) to use a dead band of 36 mHz. Therefore any changes in frequency between 59.965 and 60.035 Hertz should not trigger frequency response, but these governors with governor droop set correctly, should respond to frequencies outside the dead band. Likewise, because the governor response is ramped starting at the edge of the dead band instead of stepped, the response for a frequency that is outside but close to the dead band should be small. Therefore a change in frequency from 60.03 to 59.97 should not result in governor response, a change from 60.00 to 59.94 should result in moderate governor response, and a change from 59.97 to 59.91 should result in substantial governor response, even though all three events have the exact same frequency delta. Yet the FRM and FRO calculations treat these as equivalent events, penalizing BAAs for correctly respecting the NERC-defined dead band.

Another deficiency is the gap between 0 and 20 seconds in the measurement period. The first 8-12 seconds of an event are when frequency excursions are actually arrested. While this period is difficult to measure through Interchange metering, it is the critical period to prevent underfrequency load shedding. The measurement period lag (20-52 seconds) encourages BAAs to install controls with a 15 or 20 second delay in frequency response. Control equipment could operate less often without compromising compliance scores—certainly an unintended consequence, and one that could undermine the reliability of the Interconnection. This practice of delaying response to ensure compliance for the sake of economics at the expense of reliability is already being implemented on resources within the Western Interconnection as a direct result of the current BAL-003-1.1 measurement criteria.

Yet another issue with the FRM measure is its assumption that frequency response is linear. Although a linear assumption is reasonable for governor technology, even a governor can behave non-linearly. A step change response, capable in inverter based technology, drastically inflates the FRM measure within the first tenth of a Hertz. For example, a battery capable of injecting 10 MW upon sensing a frequency change would achieve a FRM of 10 MW/0.1 Hz for an A to B event of 0.1 Hz. That same battery would achieve a FRM of 100 MW/0.1 Hz for an A to B event of 10 mHz. The difference between FRM for the same MW injection within the first tenth of a Hertz is close to 90 MW/0.1 Hz while the difference one tenth and two tenths is only 5 MW/0.1 Hz. Because of the fraction on the denominator of the FRM equation, the equation becomes less variable for an A to B value of 0.1 Hz or greater. This needs to be accounted for in the BAL 003 standard.

There are additional problems with the number of events selected for compliance assessment and the median response requirement. By requiring selection of numerous events, regardless of how many significant frequency events occur, BAL-003 skews compliance evaluation toward events within the 36 mHz dead band. This penalizes proper performance as described above. Even if all frequency events within the dead band were excluded, the events selected to date (including previous year sample selections) have an average delta frequency of roughly 0.06 Hz. This means BAAs could remain compliant even if they carried only enough frequency responsive reserve to cover frequency changes of less than 0.1 Hz—far less than the Interconnection would need to prevent underfrequency load shedding in a major event (which is what BAL-003 is intended to prevent).

BAL-003 is intended to ensure the Western Interconnection has enough frequency responsive reserve to prevent underfrequency load shedding for a net loss of 2,440 MW, with a starting frequency of 59.976. As described above, a BAA that has installed generator controls to provide exactly that response using the NERC *Guidelines* will be penalized for not responding to small events (which is correct), whereas a BAA that carries just enough frequency responsive reserve to respond to much smaller events, or intentionally delays its response to optimize compliance over reliability, could be rewarded.

This means the Western Interconnection could experience multiple underfrequency load shedding events in a year without a single BAA failing the standard. Conversely, multiple BAAs could fail despite providing proper and reliable frequency response. Not only is this biased against BAAs that take action in good faith to follow NERC's *Guideline*, but over time, as BAAs migrate toward more cost-effective compliance methods, the Western Interconnection's initial frequency response, as well as total frequency response available, could decline.

Use of "Net Actual Interchange" to Measure Compliance with BAL-003, R1:

Net Actual Interchange (NI_A) is defined as the algebraic sum of all metered interchange over all interconnections between two physically adjacent BAAs. BAL-005-0.2b allows a scan rate of up to six seconds for both tie-line telemetry and automatic generation control (AGC) calculation. Using these values to calculate FRM has many inherent problems, and is ill suited to measure BAA response to frequency deviations caused by losses of large generating resources.

(1) The time frame for calculating a BAA's FRM is 20 to 52 seconds after a frequency deviation is identified in historical data provided by the BAA's energy management system (EMS). Many EMS/SCADA systems do not or cannot synchronize tie-line telemetry for calculation of Area Control Error (ACE) or FRM. Due to scan rates of telemetry equipment, this non-synchronization of tie-line data can dramatically skew the calculation of FRM. Although there is no intentional time delay in any of the telemetered data, permitted scan rates of up to six seconds can create lags of up to twelve seconds, depending on the timing of the event and the measurement transmitted to the host EMS for recording and calculation purposes. Measuring response beginning at 20 seconds after the frequency event is detected can skew a BAA's apparent FRM performance—whether for better or for worse, at random.

(2) Although most measurements for NI_A occur at physical meters on interties, many BAAs have pseudo-tie telemetry that does not originate from a physical meter. These pseudo-tie values are commonly associated with jointly owned generating facilities that may contribute significantly to a BAA's FRM. In addition to lag effects from scan rates of remote terminal unit (RTU) data, there are several other delays in receiving, calculating, and transmitting measurements used to calculate pseudo-tie values. Once a host BAA receives the core measurements to derive a preliminary pseudo-tie value, several additional computational and transmitting cycles must occur. At a minimum, the host BAA must run a calculation within its EMS or other control system, which may take up to six seconds. Once the value has been calculated, it is transmitted to neighboring BAAs that share the pseudo-tie value, typically through Inter-Control Center Communication Protocol (ICCP) data links. The ICCP transmittal is separate from the calculation process, with up to 12 seconds of latency between sending and receiving. As with the timing lag described in Item 1 above, the skewing effects of pseudo-tie measurements and calculation, with respect to BAL-003 compliance evaluation, are essentially random.

(3) When a frequency deviation occurs due to loss of a large generator, generator governors respond automatically to the resulting drop in frequency. If a BAA is electrically between a large resource providing frequency response and the lost generation, transmission flows can increase on the intermediary BAA's system. As transmission flows increase, transmission line losses increase as well. These losses appear as increased load on the intermediary BAA's system, which can in turn affect apparent FRM performance. In some instances, even though the BAA's generation and load response was appropriate, the losses incurred due to neighboring generator response can overwhelm the BAAs actual FRM.

(4) There is no accommodation for a BAA experiencing an intentional change to its NI_A. In previous years, scheduled interchange would be adjusted only within the 10 minutes ahead of or after the operating hour or during curtailments to manage rare unplanned transmission events. Frequency bias procedures allowed BAAs to ignore events that occurred during these intentional changes to Net Scheduled Interchange. With the advent of 15-minute scheduling, schedule changes can occur during 50 out of every 60 minutes of any operating hour. Furthermore, many BAA's representing a significant share of the WECC interconnection are currently operating in a joint 5-minute market, which results in intentional ramps at all times. This market continues to expand and other markets are developing, increasing the percentage of BAA's that experience constant intentional ramps due to NSI changes. If, by chance, a frequency deviation (selected for compliance evaluation) were to occur during this intentional re-dispatch, chances are 50%-50% that the BAA could be benefitted or harmed for BAL-003 compliance purposes. These intentional changes in Net Scheduled Interchange do not adversely affect reliability, but could harm BAA performance under BAL-003.

(5) BAAs often adjust internal generation in anticipation of daily load variations. During certain seasons, a BAA may experience relatively large changes in native load. The BAA may intentionally dispatch generation to prepare for these anticipated changes in native load and expected changes to hourly NI_A. Again, if by chance, a frequency deviation were to occur during this intentional re-dispatch, BAA compliance measurement could be improved or degraded, with no correlation to reliability.

(6) BAAs may also adjust internal generation to manage anticipated changes in output from Variable Energy Resources (VERs), primarily photovoltaic (PV) generating facilities. The California Independent System Operator (CAISO) has stated that as much as 47% if its BAA load has been served by VERs. Both increases and decreases to PV output occur on a daily basis. To manage these changes in anticipated VERs, a BAA will proactively ramp conventional generation or schedules. The result, if there is a concurrent frequency event used to measure BAL-003 compliance, is as descried above in Items 4 and 5.

Obligation for Generator Owners and Operators:

Frequency Response (FR) is a measure of an Interconnection's ability to arrest and stabilize frequency deviations following the sudden loss of generation or load, and is affected by the collective responses of generation and load throughout the Interconnection. The primary FR provided the generation fleet within an Interconnection has a significant impact on the overall FR. BAL-003 specifies the amount of frequency response (per Hertz of frequency deviation) needed from BAAs to maintain Interconnection frequency within predefined bounds and includes requirements for the measurement and provision of FR. But BAL-003 contains nothing that obligates Generator Owners/Operators (GO/GOP) to provide primary frequency response. BAAs are disadvantaged under the standard, with few options beyond expensive yearly markets for frequency responsive reserve capacity products. If BAL-003 is intended to ensure a positive frequency response to frequency excursions, then GO/GOPs must be subject to the standard.

Nothing in any other NERC standard or in the provisions of the FERC *Pro Forma* Tariff or Generation Interconnection Agreement (GIA) requires GO/GOPs to provide primary frequency response. Even a generator following the NERC Reliability Guideline – Primary Frequency Control may, in many cases, fail to respond due to the lack of headroom during an event or the blocking of the governor signal in the plant control or auxiliary systems. The BAA has no way through GIAs or tariff language to require otherwise. BAL-003 allocates a portion of the IFRO to the individual BAA, which must then attempt to allocate the obligation to all generators in the BAA. In most cases, GO/GOPs have refused to run generator units to reserve headroom for frequency response. Some GO/GOPs have asked how much they need to provide. BAAs can only explain that BAL-003 requires response expressed as a MW/0.1 Hz range. This makes it difficult to define exactly what they must provide. The retrospective nature of this standard does not enable BAAs to determine future performance and or inform GO/GOPs of their forward-looking obligation.

The ERCOT BAL-001-TRE-1, R7, "Primary Frequency Response" standard obligates the GO/GOPs to maintain functional generators and to also provide frequency response during relevant events. *"Each GO shall operate each generating unit/generating facility that is connected to the interconnected transmission system with the Governor in service and responsive to frequency when the generating unit/generating facility is online and released for dispatch, unless the GO has a valid reason for operating with the Governor not in service and the GOP has been notified that the Governor is not in service."* BAA obligations under ERCOT's standard are mostly reporting and tracking response from all generators.

FERC recognized the ERCOT standard for primary frequency response got it right and should be a pattern for future standards and revisions to current standards.[1] The ERCOT standard provides a useful model for changes needed to remedy the problems with BAL-003, or develop a Western Interconnection variance that recognizes how it differs from other regions in the NERC footprint.

NERC has pointed out that primary frequency response capability, by itself, would not require a resource to respond if called upon to help a BAA meet its FRO, and that, as a result, it is

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[1] FERC has also accepted Regional Reliability Standard BAL-001-TRE-01 (Primary Frequency Response in the ERCOT Region) as mandatory and enforceable. *North American Electric Reliability Corporation*, 146 FERC ¶ 61,025 (2014).

important to have mechanisms to ensure that sufficient frequency response capability is not only available but ready to respond at all times. If NERC believes there are mechanisms available to the BAAs, then the standard should define those mechanisms. It is unclear how NERC could expect a BAA to meet its FRO without generator response provided by governor signals.

In its Notice of Proposed Rulemaking (NOPR) on Primary Frequency Response (Docket No. RM16-6-000), FERC stated that proposed modifications to GIAs for both large and small generating facilities (both synchronous and non-synchronous) would require new generators to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection. FERC recognized that "[w]hile NERC Reliability Standard BAL-003-1.1 establishes requirements for balancing authorities, it does not include any requirements for individual generator owners or operators," and that "[w]hen considered in aggregate, the primary frequency response provided by generators within an Interconnection has a significant impact on the overall frequency response."

The NOPR also cited a 2010 NERC survey of generator owners and operators, which found that,

> ". . . only approximately 30 percent of generators in the Eastern Interconnection provided primary frequency response, and that only approximately 10 percent of generators provided sustained primary frequency response. This suggests that many generators within the Interconnection disable or otherwise set their governors or outer-loop controls such that they provide little to no primary frequency response." (Footnotes omitted)

If FERC believes that generating facilities should be capable of providing frequency response, then the NERC standard should obligate GO/GOPs to provide it. If the generators have a significant impact on the overall frequency response, why would they be excused from BAL-003 compliance?

As noted above, NERC has approved a voluntary *Reliability Guideline on Primary Frequency Control* that encourages generators to provide a sustained and effective primary frequency response. If NERC recognized that generators were not providing primary frequency response as far back as 2010, NERC should support changes to the BAL-003 to obligate GO/GOPs to enable compliance.

There is compelling evidence and testimony from multiple sources—BAs, transmission operators, and NERC reports—to show that generators, a major source of primary frequency response, are not providing the appropriate response to frequency excursions. There is no "mechanism" available to the BAAs to compel generators to provide the necessary primary frequency response during an event. BAL-003 must be revised to address this.

Assumptions Behind the Current Standard:

BAL-003 appears to assume that all BAAs have the same composition and operate in the same manner. This may accurately describe the Eastern Interconnection. However, the Western Interconnection encompasses 38 BAAs that differ widely from one another.

Within the Western Interconnection, some BAAs are generation only, with 100% wind generation; some are generation only with 100% thermal generation; others serve load, with 100% hydro generation; and there are many other combinations.

BAL-003 rests on the assumption that as one BAA fails, the statistical probability is that other BAAs will provide sufficient excess response. But generation-only BAAs are driven by market conditions, which do not correlate to the timing of frequency events. BAL-003 allocates IFRO using a formula that has no bearing on a BAA's ability to provide frequency response. In addition, the formula uses two-year-old data to allocate IFRO. A generation-only BAA is driven by real-time conditions, not by two-year old data.

In addition, BAL-003 does a poor job of recognizing and accommodating BAA changes over time. The single largest Western Interconnection BAA (CAISO) has experienced significant changes related rooftop solar. With the installation of rooftop solar, CAISO's calculated load has decreased by over 5,000 MW, along with the reduction of the BAA calculated generation by over 5,000 MW. Under the formula to allocate IFRO, the presence of rooftop solar will reduce CAISO's FRO. At the same time, rooftop solar provides no inertia to support frequency response. Allowing large offsets from rooftop solar to reduce FRO runs counter to reliability, unfairly burdening and imposing disparate treatment on remaining BAAs. The unintended consequence is to encourage BAAs to increase the how much of their generation is behind the meter, thereby reducing their allocations of FRO. NERC's reliability standards should treat similarly situated responsible entities comparably, not create disparities among them. BAL-003 lacks flexibility to address real-time changes and real-time reliability requirements.

There is also no provision in the standard for generation that moves from one BAA to another. The BAA that lost the generation will still be held to a larger FRO than is justified by the amount of generation left in the BAA and the FRO of the attaining BAA will not change based on the increase in the amount of generation in the BAA.

Goal of a Reliability Standard

The foregoing discussion is not meant to imply that BAL-003 is completely without merit. It has brought frequency response to the forefront of many operational discussions. Some BAA operators have already taken steps to improve machine capability, change dispatch, and acquire Frequency Response Transfer from BAAs with excess. BAL-003 has moved the industry forward in its knowledge of frequency response. At the same time, it misaligns incentives for compliance and what is actually needed for reliability. This misalignment potentially drives progress in equipment, operations, and markets in the wrong direction.

To better ensure reliability, BAL-003 standard should:

- Address real-time reliability and not rely upon historical analysis and median performance. The standard needs to be flexible to address differing conditions and future changes.
- Ensure frequency response occurs to arrest rapid frequency decline and prevent underfrequency load shedding.
- Avoid unintended consequences, such as encouraging BAAs to time their response well after Point C and in the measurement period (Point B)
- Require testing of frequency responsive equipment
- Ensure comparability among all responsible entities needed for primary frequency response

SUMMARY

Real-Time Reliability

- BAL-003 as currently configured does not require response to an event. Frequency response is needed 24 hours a day, 365 day a year to manage variations in Interconnection frequency.
- Historical event-driven analysis does not ensure frequency response is available in real-time.
- Because the current standard measures historical response, and is measured by performance at the median event, the Interconnection could experience underfrequency load shedding in real-time without any compliance failures.
- The allocation of IFRO is predicated on two-year-old information, which does not reflect the Interconnection's frequency response needs in real-time.
- When a significant amount of generation trips off-line, frequency response is necessary within the first 20 seconds to arrest and stabilize rapid frequency decline. BAL-003 measures the average frequency support in the 20 to 52 second period following the event, which encourages BAAs to delay response to improve compliance. This subverts the primary purpose of the standard, and could drive less real-time reliability, not more.

Event Selection

- Current BAL-003 is driven by historical analysis of selected events and the selection criteria does not always measure frequency response. Performance metrics should reflect dead bands, beginning frequency, size and type of events, an adequate number of events, and most importantly time of measurements.
- Frequency response is mechanically driven, and can be accurately measured only during machine movement.

Measurement

- The current standard uses Net Interchange Actual (NI_A) to measure compliance. To have good measurement, one must have good statistics to support the values measured.

- NI_A is made up of several variables, changes in load, changes in generation, changes in purchases, pseudo-tie values, changes in transmission flows and losses, frequency response, and others. Statistical analysis can support measurement only when all inputs can be determined to isolate the value being measured for compliance. NI_A has far too many variables, all changing at the same time, to be treated as the sole measure of frequency response.
- Dynamic schedules are not included in the measurement, even though they may have a response component.
- Battery insertion or other responsive measures can be timed to occur in the measurement period thereby missing the arrestment period and subverting the purpose of the standard.
- Frequency response is not linear thus distorting the FRM measure, especially for events with an A to B measure less than 0.1 Hz

Assumptions Behind Current Standard

- BAL-003 appears to assume that all BAAs have the same composition and operate in the same manner. This may accurately describe the Eastern Interconnection. However, the Western Interconnection encompasses 38 BAAs that differ widely from one another.
- 100% generation only, wind only, 100% hydro base, 100% thermal base, many different mixtures
- The standard fails to recognize the changes associated with solar, and impacts associated with behind-the-meter solar. The allocation formula rewards a BAA with behind-the-meter solar and places the burden of frequency response on the remaining BAAs.

Unofficial Comment Form

Project 2017-01 Modifications to BAL-003-1.1

Do not use this form for submitting comments. Use the electronic form to submit comments on the **Project 2017-01 Modifications to BAL-003-1.1** project. The electronic form must be submitted by **8 p.m. Eastern, Friday, December 1, 2017**.

Documents and information about this project are available on the Project 2017-01 Modifications to BAL-003-1.1 page. If you have questions, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

Background

Two Standards Authorization Requests (SARs) were received for modifying BAL-003-1.1. The first SAR was submitted by the NERC RS and was posted for industry comment from June 19, 2017 through July 18, 2017. The second SAR was submitted by the NWPP FRSG. This SAR proposes a two phase approach to modifying the current standard, The Phase I portion of the SAR was addressed during the posting and comment period for the NERC RS SAR (June 19, 2017 through July 18, 2017). This comment period will only address the Phase II portion of this SAR. The Phase II portion of the SAR proposes to:

- Consider revising BAL-003-1.1 standard to reflect real-time measurement of frequency performance vs. a two year old allocation.
- Consider revising BAL-003-1.1 Standard to reflect the correct applicable entity that controls and provides frequency response.
- Consider revising BAL-003-1.1 Standard to reflect comparability among the applicable entities.
- Consider revising BAL-003-1.1 Standard to eliminate arbitrary allocation of responsibility.
- Consider revising BAL-003-1.1 Standard to eliminate the incorrect signals that have created unintended consequences.

Please provide your responses to the questions listed below along with any detailed comments.

Questions

1. The SAR proposes to modify the current BAL-003-1.1 standard to reflect the correct applicable entity that controls and provides frequency response, to reflect comparability among the applicable entities, and to eliminate arbitrary allocation of responsibility. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

   ☐ Yes
   ☐ No

   Comments:

2. The SAR proposes to modify the current BAL-003-1.1 standard to allow for real-time measurement of frequency performance instead of a two year old allocation. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

   ☐ Yes
   ☐ No

   Comments:

3. The SAR proposes to modify the current BAL-003-1.1 standard to eliminate the incorrect signals to the market for arbitrary pricing and conditions. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

   ☐ Yes
   ☐ No

   Comments:

4. Based on the scope of the Phase II section of the SAR, do you have any other comments for drafting team consideration?

   ☐ Yes
   ☐ No

   Comments:

Standards Announcement

Project 2017-01 Modifications to BAL-003-1.1
Standards Authorization Request

Formal Comment Period Open through December 1, 2017

Now Available

An additional Standards Authorization Request (SAR) for **BAL-003-1.1 Frequency Response and Frequency Bias Setting** was submitted by the Northwest Power Pool Frequency Response Sharing Group. A 30-day formal comment period on this SAR is open through **8 p.m. Eastern, Friday, December 1, 2017.**

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience difficulties navigating the SBS, contact Nasheema Santos. An unofficial Word version of the comment form is posted on the project page.

If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).

- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The drafting team will review all responses received during the comment period and determine the next steps of the project.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

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Comment Report

Project Name:	2017-01 Modifications to BAL-003-1.1 | Standards Authorization Request
Comment Period Start Date:	11/2/2017
Comment Period End Date:	12/1/2017
Associated Ballots:	

There were 42 sets of responses, including comments from approximately 115 different people from approximately 75 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The SAR proposes to modify the current BAL-003-1.1 standard to reflect the correct applicable entity that controls and provides frequency response, to reflect comparability among the applicable entities, and to eliminate arbitrary allocation of responsibility. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

2. The SAR proposes to modify the current BAL-003-1.1 standard to allow for real-time measurement of frequency performance instead of a two year old allocation. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

3. The SAR proposes to modify the current BAL-003-1.1 standard to eliminate the incorrect signals to the market for arbitrary pricing and conditions. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

4. Based on the scope of the Phase II section of the SAR, do you have any other comments for drafting team consideration?

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
PJM Interconnection, L.L.C.	Albert DiCaprio	2	RF,SERC	ISO Standards Review Committee	Charles Yeung	SPP	2	SPP RE
					Ben Li	IESO	2	NPCC
					Mark Holman	PJM	2	RF
					Kathleen Goodman	ISONE	2	NPCC
					Greg Campoli	NYISO	2	NPCC
					Terry Bilke	MISO	2	RF
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Mark Ringhausen	Old Dominion Electric Cooperative	4	SERC
					Mark Ringhausen	Old Dominion Electric Cooperative	3,4	SERC
					Ryan Strom	Buckeye Power, Inc.	5	RF
					Ryan Strom	Buckeye Power, Inc.	4	RF
					Patrick Woods	East Kentucky	1,3	SERC

						Power Cooperative		
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
Public Utility District No. 1 of Chelan County	Janis Weddle	1,3,5,6		Chelan PUD	Haley Sousa	Public Utility District No. 1 of Chelan County	5	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Jeff Kimbell	Public Utility District No. 1 of Chelan County	1	WECC
					Janis Weddle	Public Utility District No. 1 of Chelan County	6	WECC
Consumers Energy Company	Jeanne Kurzynowski	1,3,4,5	RF	Consumers Energy Company	Jeanne Kurzynowski	Consumers Energy Company	1,3,4,5	RF

					Jim Anderson	Consumers Energy Company	1	RF
					Karl Blaszkowski	Consumers Energy Company	3	RF
					Theresa Martinez	Consumers Energy Company	4	RF
					David Greyerbiehl	Consumers Energy Company	5	RF
Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc	1	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC
					William Shultz	Southern Company Generation	5	SERC
Manitoba Hydro	Mike Smith	1,3,5,6		Manitoba Hydro	Yuguang Xiao	Manitoba Hydro	5	MRO
					Karim Abdel-Hadi	Manitoba Hydro	3	MRO
					Blair Mukanik	Manitoba Hydro	6	MRO
					Mike Smith	Manitoba Hydro	1	MRO
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion NextERA Con-Ed ISO-NE	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC

					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					Greg Campoli	NYISO	2	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Brent Hebert	Northeast Texas Electric Cooperative - HCCP	5	SPP RE
					Louis Guidry	Cleco Corporation	1,3,5,6	SPP RE
					Robert Hirchak	Cleco Corporation	6	SPP RE

PPL - Louisville Gas and Electric Co.	Shelby Wade	2,5,6	RF,SERC	Louisville Gas and Electric Company and Kentucky Utilities Company	Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					Dan Wilson	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC

1. The SAR proposes to modify the current BAL-003-1.1 standard to reflect the correct applicable entity that controls and provides frequency response, to reflect comparability among the applicable entities, and to eliminate arbitrary allocation of responsibility. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.	
Thomas Foltz - AEP - 3,5	
Answer	No
Document Name	
Comment	
AEP does not believe that BAL-003 -1.1 requires the BA to be directly responsible for providing primary frequency response. Rather, it sets the expectations for the performance of the BA in recovering from a frequency event with secondary frequency response through AGC. In our opinion, the allocation of responsibility is not arbitrarily assigned to the BA, but rather correctly assigned to the BA. Having said that, it seems the standard's Purpose statement is somewhat out of step with the requirements themselves and perhaps should be revised to better align with those requirements.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
The apparent implication is that GOPs have responsibility for primary frequency response (PFR). Even for PFR, coordination of frequency response capability lies with BAs or collections of BAs, not with individual resources. For example, a BA may have ample frequency responsive resources available, but if it chooses not to have enough of them online with adequate headroom, frequency response will not be adequate. A standard to require resources to have frequency responsive capability may have merit, but combining that with the responsibilities of BAs may very likely lead to unneeded confusion. The background document cites ERCOT's BAL-001-TRE-1 as a model, but it is a separate standard, not a replacement for BAL-003. Regarding comparability and allocation, we do not agree that the difference in resource mix or the amount of native BA load warrant a difference in treatment. The mechanism currently employed parallels the basis for NERC and RE funding allocation and has essentially the same time lag.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	

Answer	No
Document Name	

Comment

AZPS can support exploring whether additional functional entities should be addressed in the applicability section of the standard and/or with targeted requirements. However, AZPS cautions against creating redundant requirements in these reliability standards as FERC is currently proposing changes in the Open Access Transmission Tariffs. Finally, AZPS cannot outright support a need for a revision without evidence of a study or evaluation of the need to add additional applicable entities and without indication regarding the entities to which any associated revision would be directed.

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

We do agree with the concept of properly allocating responsibility. The phased approach needs to be two distinctive processes. We should not delay the correction proposed in phase I to incorporate any proposed modifications that are noted in phase II. This SAR needs to address only the changes required after modifications of Phase I are complete.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

The IESO believes that the Balancing Authority is the appropriate entity responsible for assuring that its ACE performance is compliant with the current BAL performance requirements.

Likes 0	
Dislikes 0	

Response

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	No
Document Name	
Comment	
PJM supports the exploration of a capability requirement for GOPs to provide primary frequency response. However, PJM sees this as supplemental, not a replacement of the BA requirement. PJM does not believe it is appropriate to reflect comparability among applicable entities. A BAs load response, or mix and type of generation should not play a role in the primary frequency response allocation	
Likes 0	
Dislikes 0	
Response	

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - SERC,RF, Group Name ISO Standards Review Committee	
Answer	No
Document Name	
Comment	
The SRC supports the position that the Balancing Authority is the correct responsible entity for assuring that its ACE performance is compliant with the current BAL performance requirements.	
Likes 0	
Dislikes 0	
Response	

Shelby Wade - PPL - Louisville Gas and Electric Co. - 2,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	No
Document Name	
Comment	
Frequency Response (FR) is a function of both generating resources and load characteristics – both fall under the purview of the BA. A BA can set performance requirements for resources within its balancing authority area (BAA), which includes governor/inverter settings. Similar to reactive/voltage requirements, a GO/GOP must meet FR performance criteria set by the BA/TO/TOP. FR is maintained by BA coordination of all assets within the BAA. The proposal to modify the functional entity applicability for BAL-003-1.1 to add the GO/GOP does not give any additional assurance of FR related interconnection reliability as an individual resource may or may not have the ability to respond as intended for a specific frequency event; however, the proposed modification will significantly increase the operating, economic and	

administrative burdens on the GO/GOP. The perceived improvement in FR related reliability intended by broadening the applicability of the standard does not justify the added burdens that would be placed on all GO/GOPs.	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	
For Chelan PUD, as a BAA that owns and operates all of the generation within the BAA, the current standard is sufficient.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
The SAR proposes to modify the standard to a single entity that has the "ability to" provide and control Frequency Response. We caution that an entity providing Frequency Response may not be the same entity that controls Frequency Response. We also believe some accountability should still exist with the Frequency Response Sharing Group or seclusive Balancing Authority to monitor Frequency Response sufficiency for their respective area.	
Likes 0	
Dislikes 0	
Response	
Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	No
Document Name	
Comment	

Tacoma Power believes that although Balancing Authorities do not inherently have frequency responsive capabilities, these capabilities can be acquired via contractual agreements and market products. FERC should consider providing direction as to who should be compensating BAs for acquiring frequency response products necessary to meet this standard.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed ISO-NE	
Answer	No
Document Name	
Comment	
NPCC believes that the Balancing Authority is the appropriate entity responsible for assuring that its ACE performance is compliant with the current BAL performance requirements.	
Likes 0	
Dislikes 0	
Response	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	
Comment	
Tri-State believes this revision is not necessary due to the obligations already existing in TOP-001-3. As required by TOP-001-3 Requirement R5, a Generator Operator must comply with each Operating Instruction issued by its Balancing Authority. This would already include providing frequency response when asked to. Therefore, Tri-State believes it is incorrect to state that there is no mechanism available to Balancing Authorities to compel generators to provide frequency response during an event.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	

Comment	
SRP believes the responsibility is appropriately allocated to the Balancing Authority.	
Likes 0	
Dislikes 0	
Response	
Casey Johnston - Concerned Electrical Engineer with 40 yrs in Electrical Industry - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
The majority of frequency response is provided by rotating masses, such as generators with synchronized torque and motors connected to the interconnection. There is compelling evidence and testimony from multiple sources—BAs, transmission operators, and NERC reports—to show that many synchronous generators, the primary source of primary frequency response, are not providing the expected proportional response to frequency excursions. This standard, BAL-003, should apply to NERC registered GO/GOPs as responsible entities.	
Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1 - WECC	
Answer	Yes
Document Name	
Comment	
The majority of frequency response is provided by rotating masses, such as generators with synchronized torque and motors connected to the interconnection. There is compelling evidence and testimony from multiple sources—BAs, transmission operators, and NERC reports—to show that many synchronous generators, the primary source of primary frequency response, are not providing the expected proportional response to frequency excursions. Currently, there is no “mechanism” available to the BAs to compel Generator Owners or Generator Operators to have their facilities provide the necessary primary frequency response during an event. BAL-003 must be revised to address this shortcoming. This standard, BAL-003, should apply to NERC registered GO/GOPs as responsible entities.	
Likes 0	
Dislikes 0	

Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
Puget Sound Energy (PSE) fully supports the SAR for Project 2017-01 and the proposed revisions. To address reliability, BAL-003-1.1 should be modified to impose requirements on individual generating facilities and not burden Balancing Authorities with the cost of procuring frequency response in the marketplace.	
Likes 0	
Dislikes 0	
Response	
Antonio Franco - Gridforce Energy Management, LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Gridforce Energy Management agrees and supports the SAR. Not all Balancing Authorities own an asset to contrubute with primary frequency response, which in the Western Interconnection is generally a synchronous generator governor.	
Likes 0	
Dislikes 0	
Response	
James Ramos - Turlock Irrigation District - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Frequency response is mostly provided by motors and generators synchronized to the interconnection. There is compelling evidence and testimony from multiple sources—BAs, transmission operators, and NERC reports—to show that many synchronous generators, the primary source of primary frequency response, are not providing the expected proportional response to frequency excursions. Generator Owners (GOs) or Generator Operators (GOPs) should be required to have their facilities provide the necessary primary frequency response during an event. BAL-003 applicable to GOs and GOPs.	

Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
The majority of frequency response is provided by generators, but yet, the current BAL-003-1.1 applicability section requires Balancing Authorities to comply with the standard. This standard does not provide any mechanism to compel Generator Owners or Generator Operators to provide the necessary primary frequency response during an event. In addition, the Balancing Authorities do not have authority to force the Generator Owners or Generator Operators to respond correctly in the case of an event.	
Likes 0	
Dislikes 0	
Response	
Yvonne McMackin - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes
Document Name	2017-BAL003 SAR Unofficial_Comment_Form_NWPP_Nov2017_Grant PUD.docx
Comment	
Different types of generation and load have different abilities to provide frequency response, and the BA in which the generation or load is located is not necessarily the owner of the generation or load. The standard should recognize the fact that the BA may not be the owner and also allow for generators and load that do supply frequency response to be appropriately compensated for this service.	
Likes 0	
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Austin Energy (AE) agrees with the revision to eliminate arbitrary allocation of responsibility. However, AE requests that Generator Owners and	

Generator Operators in the ERCOT Interconnection be exempted from this requirement. The Regional Standard, BAL-001-TRE-1 - Primary Frequency Response incorporates specific performance requirements for Generator Owners and Generator Operators related to setting Governor dead-band and droop parameters and providing Primary Frequency Response. In the ERCOT Interconnection, all generator governors (unless exempted by ERCOT) must be in service and performing with an un-muted response to ensure an Interconnection minimum Frequency Response to a frequency disturbance event.

Likes 0	
Dislikes 0	
Response	

Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
The majority of frequency response is provided by rotating masses, such as generators with synchronized torque and motors connected to the interconnection. There is compelling evidence and testimony from multiple sources—BAs, transmission operators, and NERC reports—to show that many synchronous generators, the primary source of primary frequency response, are not providing the expected proportional response to frequency excursions. Currently, there is no “mechanism” available to the BAs to compel Generator Owners or Generator Operators to have their facilities provide the necessary primary frequency response during an event. BAL-003 must be revised to address this shortcoming.	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
SCL is both a BA and a GO/GOP. So this proposed revision will not change SCL’s responsibility.	
Likes 0	

Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Frequency response is a measure of an interconnection's post-contingency response, and in WECC that comes primarily from generator governor action. Putting the obligation on the BA without also providing authority over the GOP to require frequency response creates a system where many entities do not have the means to meet compliance. Even if the allocation of obligation is corrected, it does not change the fact that the current metric of FRM does not accurately measure frequency response. It can be clearly shown that change in BAA net interchange does not accurately measure the frequency response supplied by that BAA if it is in a finite interconnection. By using interchange as a proxy for frequency response in a finite interconnection, we are left with a zero-sum game where BAs compete for a share of the contingent unit credit. This has created a situation where in order to meet compliance, it can be beneficial to reduce system reliability by delaying/gaming governor settings. Alternatively, it is possible for a BA to unilaterally over-respond and cause other entities to fail where their only recourse for compliance is to purchase FRM from that entity or shed load.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
The majority of frequency response is provided by rotating masses, such as generators with synchronized torque and motors connected to the interconnection. There is compelling evidence and testimony from multiple sources—BAs, transmission operators, and NERC reports—to show that many synchronous generators, the primary source of primary frequency response, are not providing the expected proportional response to frequency excursions. Currently, there is no "mechanism" available to the BAs to compel Generator Owners or Generator Operators to have their facilities provide the necessary primary frequency response during an event. There may be other resources available to provide primary frequency response, but there is also no "mechanism" available to compel these operating entities configure their facilities to provide primary frequency response. BAL-003 must be revised to address this shortcoming.	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 1,3,5,6	

Answer	Yes
Document Name	
Comment	

BAL-003 should be revised to include some sort of mechanism for BAs to compel GOs and GOPs to provide the necessary primary frequency response during events. Currently there is no such mechanism, despite the fact that there is strong evidence that many synchronous generators, whose rotating masses provide the majority of frequency response, are not providing a proportional response to frequency events.

Likes 0	
Dislikes 0	
Response	

David Ramkalawan - Ontario Power Generation Inc. - 5

Answer	Yes
Document Name	
Comment	

OPG agrees with closing the reliability gap with respect to the applicable entity as long as the requirements to the GO/GOP are properly and clearly defined.

OPG support the clarification of non-synchronous generation compliance obligation for the provision of essential reliability services like frequency control and ramping capability/flexible capacity.

We are also in agreement with the revision of the allocation formula to adequately reflect the composition of the grid and more accurately place the burden of frequency response.

Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	Yes
Document Name	
Comment	

Texas RE appreciates the SDT's efforts to properly align compliance responsibilities for providing frequency response with those Registered Entities actually capable of performing that specific reliability task. To that end, Texas RE agrees that the BAL-003 Standard should impose certain mandatory frequency response requirements on Generation Owners (GO) and Generation Operators (GOP). As the accompanying technical guidance document sets forth, the current BAL-001-TRE-1 Standard requires GOs and GOPs to set governor droop and deadband settings in accordance with specified criteria (BAL-001-TRE-1 R6), operate with their governor in service (BAL-001-TRE-1 R7), and meet both initial and sustained frequency response

performance metrics (BA-001-TRE-1 R9 and R10). Texas RE recommends that the SDT consider these collective approaches in designing a new BAL-003 Standard.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
The majority of frequency response is provided by rotating masses, such as generators with synchronized torque and motors connected to the interconnection. There is compelling evidence and testimony from multiple sources—BAs, transmission operators, and NERC reports—to show that many synchronous generators, the primary source of primary frequency response, are not providing the expected proportional response to frequency excursions. Currently, there is no “mechanism” available to the BAs to compel Generator Owners or Generator Operators to have their facilities provide the necessary primary frequency response during an event. BAL-003 must be revised to address this shortcoming. For small BAs with a limited amount of generation and tie lines Net Interchange does not provide a precise measure of actual response when the required response for a BA is less than 1 MW/0.1Hz during a disturbance. Tie line meters toggling a single whole MW in the incorrect direction could make it appear that the BA responded in the wrong direction when generation does show a response in the correct direction.	
Likes 0	
Dislikes 0	
Response	
Jeff Rehfeld - NaturEner USA, LLC - 5 - WECC	
Answer	Yes
Document Name	
Comment	
Comments: The majority of frequency response is provided by rotating masses, such as generators with synchronized torque and motors connected to the interconnection. There is compelling evidence and testimony from multiple sources—BAs, transmission operators, and NERC reports—to show that many synchronous generators, the primary source of primary frequency response, are not providing the expected proportional response to frequency excursions. Currently, there is no “mechanism” available to the BAs to compel Generator Owners or Generator Operators to have their facilities provide the necessary primary frequency response during an event. BAL-003 must be revised to address this shortcoming, subject to the considerations set forth in the immediately following paragraph. A one-size fits all blanket rule should not be imposed which requires all generators to have to install capability to provide primary frequency response above their inherent characteristics/capabilities. Among other things, mandating that all generators be required to install capabilities to provide primary frequency response (1) fails to take into account the individual characteristics of different generator types and their unique advantages and disadvantages (e.g., wind generators’ limited ability and cost-prohibitive impact of providing primary frequency response in an under-frequency event	

situation) as well as diversity benefits, (2) is uneconomical and will result in an inefficient use of limited resources (the costs may often dwarf any limited benefit), (3) may result in an oversupply of frequency response, (4) will hinder if not effectively “crowd out” the development of more efficient approaches including options for compliance offered (or at least complemented) by frequency response sharing groups/pools, bilateral contracts and other always emerging market solutions, and (4) may decrease the ability to provide secondary frequency response.

Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
Adding the frequency response obligation to the BA without also providing authority over the GOP to require frequency response creates a system where some entities may not have the means to meet compliance. Using interchange as a proxy for frequency response may be inaccurate and needs further review.	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF, Group Name Consumers Energy Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	
Comment	

BPA is a member of the WFRSG and supports the WFRSG SAR. There are many things in the current BAL-003 standard that need to be changed.

BPA assumes this question relates to adding the GO/GOP to the list of applicable entities for this standard. BPA disagrees that the GO/GOP should be added to the list of responsible entities. BPA believes that the BA is the responsible entity for this standard. Frequency Response should be considered another product procured from a generator or load by the BA to meet its responsibilities the same as Schedules 3, 5 and 6. The BA has the wide area view needed for determining the amount of frequency responsive reserve that should be held to meet its compliance obligation. BPA is concerned that a GO/GOP requirement could lead to inefficient operations of a generation fleet, because too much capacity would be held aside for frequency response. Through participation in the WFRSG BPA has heard the concerns of many BA’s related to the current BAL-003 standard and respects their position regarding their inability to require a generator to provide frequency response. BPA believes that the Standard Drafting Team should hear arguments and fully evaluate the standard to determine the correct applicable entity or entities. In addition, BPA takes issue in how this question is presented. BPA did not see a specific proposed revision in the above question, and therefore finds it hard to answer either yes or no. Instead BPA was forced to make its own assumptions regarding what the question pertained to. Therefore we cannot provide specific language, because no specific revision was proposed. In general, BPA does support the drafting team considering a revision to the standard to reflect what is required for real-time reliability.

Likes 0	
Dislikes 0	

Response

2. The SAR proposes to modify the current BAL-003-1.1 standard to allow for real-time measurement of frequency performance instead of a two year old allocation. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6	
Answer	No
Document Name	
Comment	
AECI has concerns with the proposed modifications that allow for real-time frequency performance instead of a two year old allocation. Sufficient detail has not been presented in regards to this approach. Would a Responsible Entity be required to meet frequency response obligations for every event? Would there be any exemptions for a Responsible Entity that is experiencing the generation loss? AECI sees merit in the approach, but cannot agree with the proposal in question 2 until further details are provided.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Without a clear proposed method of Real-Time measurement, SRP cannot support the implementation of such a change. Neither can SRP provide specific language revisions. SRP is concerned the proposed transition to Real-Time measurement could incur high costs from overly strict operating conditions or other unforeseen consequences. Moreover, the current measure, though retrospective, is effective in creating sufficient frequency response in each interconnection.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed ISO-NE	
Answer	No
Document Name	
Comment	
Linking real time frequency to real time asset response may be inappropriate since generation production may not be not a continuous function of each asset. NPCC supports the current concept that the diversity of primary response is properly reflected in the use of long-term average frequency for	

computing the bias settings utilized in the ACE equation.	
Likes 0	
Dislikes 0	
Response	
Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Tacoma Power does not believe real time monitoring should be prescribed through reliability standards. However, Tacoma believes that behind the meter solar has become prevalent enough so that it requires both the generator and load, which are behind the meter, be included in the BAs portion of the Interconnection Frequency Reserve Obligation.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Xcel Energy has concerns on how this would be implemented. It is important to be able to look at the data from each event to verify accuracy and make adjustments. Synchronized real time data would be optimal and may be required. Further, if generator owners will be required to operate with governors in-service with defined droop and deadband, allowances must be made for generator owners to notify transmission coordinators if a failure occurs that prevents equipment from operating in its normal manner and prevents frequency response. The AGC frequency bias logic is used so AGC signal does not wash out primary frequency response of turbine-generators. This can also be applied for other equipment failure modes.	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Chelan PUD	
Answer	No

Document Name	
Comment	

While the allocation may use two-year-old data, Chelan PUD believes the standard is sufficient for its intended purpose.

Likes 0	
Dislikes 0	
Response	

Shelby Wade - PPL - Louisville Gas and Electric Co. - 2,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company

Answer	No
Document Name	
Comment	

Concern over Frequency Response (FR) to large, infrequent loss of resource events that significantly impact interconnection frequency has taken years to develop and rose to a level justifying the creation of a reliability standard (BAL-003-1.1). The standard is relatively new and has been effective in raising awareness of FR and assigning responsibility for FR performance. Unless there is evidence that the standard is not stabilizing/improving an interconnection's FR, it seems premature to take the significant step of making FR a real-time reliability issue.

Making FR a real-time issue would have significant operating, economic and administrative impacts. The provision, monitoring and reporting of FR Resources (FRR) would be analogous to Operating Reserves (Contingency and Regulating Reserves). Such an effort does not seem justified unless the inadequacy of the current BAL-003-1.1 can be clearly demonstrated and there is a lack in reliability.

If a new way of calculating FR is proposed utilizing real-time information, then NERC should consider a voluntary field trial using the new methodology (similar to BAAL). This would allow companies to assess their historical FR calculation and compare it to the FR calculated under a new methodology.

Likes 0	
Dislikes 0	
Response	

Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - SERC,RF, Group Name ISO Standards Review Committee

Answer	No
Document Name	
Comment	

The concept of linking real time frequency to real time asset response ignores the fact that generation production is not a continuous function for each asset. The SRC supports the current concept that the diversity of primary response is properly reflected in the use of long-term average frequency for computing the bias settings utilized in the ACE equation.

Likes 0	

Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	No
Document Name	
Comment	
PJM sees merit in real-time measurement in frequency response reserves and performance. However, PJM does not see this as a replacement for the historical performance assessments and allocations of frequency bias.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
Linking real time frequency to real time asset response may be inappropriate since generation production may not be not a continuous function of each asset. The IESO supports the current concept that the diversity of primary response is properly reflected in the use of long-term average frequency for computing the bias settings utilized in the ACE equation.	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
The scope and complexity of the work defined in the SAR indicates a large effort which if incorporated with Phase I will delay making the needed corrections. The phased approach needs to be two distinctive processes. We should not delay the correction proposed in phase I to incorporate any proposed modifications that are noted in phase II. This SAR needs to address only the changes required after modifications of Phase I are complete.	

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6

Answer	No
Document Name	

Comment

It is unclear whether the real-time measurement would wholly replace the current method for calculation and allocation or is being proposed to provide additional benefits in real-time. Without clarity regarding the proposal and its potential for impacts, AZPS is concerned that the SAR is not clear enough to allow for proper evaluation. If the intent is to wholly replace the current methods of calculation and allocation, AZPS cannot support such proposal as such would significantly increase costs and complicate resource planning and adequacy efforts. No evidence has been offered as to reliability issues occurring due to neither the current method nor how a real-time measurement would resolve those issues.

Likes 0	
Dislikes 0	

Response

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body

Answer	No
Document Name	

Comment

Although City Light agrees with the issues identified with the current standard (such as the assumption that frequency response is linear; using last two-year information to allocate IFRO; and performance is determined by the median event of historical responses,) City Light still thinks the existing standard is sufficient for the intended use at this time. To do the calculations for the real-time measurement of frequency performance for all kinds of real time system conditions and next N-1 contingencies will be very difficult to implement and probably will not be cost effective.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

Real-time measurement of frequency performance has merit, but it should be in addition to, not a substitute for, determination of frequency bias settings. Much like DCS requirements, there is merit in requirements for both performance and longer term determination of minimum response requirements.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	No
Document Name	
Comment	
AEP believes that a Real-time assessment of frequency performance, or an after-the-fact assessment of frequency performance such as required in BAL-001-TRE, is neither possible nor advisable for an interconnection having excess synchronous inertia that limits the extent of n-1 frequency events. The "two year old allocation" of the existing standard is sufficient for the intended use at this time.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
Allowing for a real-time measurement of frequency performance appears to be an improvement.	
Likes 0	
Dislikes 0	
Response	
Jeff Rehfeld - NaturEner USA, LLC - 5 - WECC	
Answer	Yes

Document Name	
Comment	
Comments: Frequency response is required and provided during real-time resource contingencies within the interconnection. Currently BAL-003-1.1 does not measure at the time of the event the ability to provide frequency response nor does it identify the parties that may have the ability to respond under the current real-time topology (transmission, generation and demand). Utilizing two year old data to allocate the Interconnection Frequency Response Obligation fails to recognize real-time conditions and how topologies may change.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Frequency response is required and provided immediately after an event occurs within the interconnection. Currently BAL-003-1.1 provides no mechanism to ensure the availability to provide frequency response at the time of the event nor does it reflect current real-time topology that may limit the ability to respond (transmission, generation and demand). The use of historical data to determine the median response for BAL-003 compliance reporting provides no assurance that all BAs will respond realtime to all disturbances. If a Balancing Authority has a known shortage during a certain time of year the BA could chose to not provide the required response for that period and rely on the rest of the events in the compliance period to pass the standard given the current measurement criteria. Utilizing two year old data to allocate the Interconnection Frequency Response Obligation fails to recognize real-time conditions and how topologies may change.	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG agrees with the real-time measurement of frequency performance and expresses concerns with respect to the extent of the implications for all involved existing ICCP communication/control links that do not satisfy the latency requirements.	
Likes 0	
Dislikes 0	

Response	
Angela Gaines - Portland General Electric Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
The current standard's use of two-year old data does not take into account real-time conditions and the changing nature of topologies and therefore does not provide an adequate way of measuring frequency performance. The standard should be revised to address the ability of a party to provide real-time frequency response during resource contingencies.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Frequency response is required and provided during real-time resource contingencies within the interconnection. Currently BAL-003-1.1 does not measure at the time of the event the ability to provide frequency response nor does it identify the parties that may have the ability to respond under the current real-time topology (transmission, generation and demand). Utilizing two year old data to allocate the Interconnection Frequency Response Obligation fails to recognize real-time conditions and how topologies may change.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Load and generation profiles are rapidly changing, and using old data from Form 714 to allocate a static obligation is grossly inaccurate. Once again, the standard incorrectly assumes that every BA is identical when there exist vast differences in load profiles and resource mix. Allocation would have to be real-time and dynamic in order to be accurate. In WECC, BAA's are currently required to calculate 3% of their real time load and generation, and this value is used as a requirement for Contingency Reserves. Additionally a real time calculation of estimated available capacity is also required. A	

similar real time calculation should be feasible and could more accurately represent system conditions in real time for the purposes of frequency response requirements.

Likes 0	
Dislikes 0	

Response

Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC

Answer	Yes
Document Name	

Comment

Frequency response is required and provided during real-time resource contingencies within the interconnection. Currently BAL-003-1.1 does not measure at the time of the event the ability to provide frequency response nor does it identify the parties that may have the ability to respond under the current real-time topology (transmission, generation and demand). Utilizing two year old data to allocate the Interconnection Frequency Response Obligation fails to recognize real-time conditions and how topologies may change.

Likes 0	
Dislikes 0	

Response

Andrew Gallo - Austin Energy - 1,3,4,5,6

Answer	Yes
Document Name	

Comment

AE agrees with the modification to allow for real-time measurement of frequency events to assess primary frequency performance. However, AE requests the ERCOT Interconnection be exempted from this requirement. The Regional Standard, BAL-001-TRE-1 - Primary Frequency Response incorporates specific requirements for the Balancing Authority related to identifying actual real-time Frequency Measureable Events, calculating the Primary Frequency Response of each generation resource in the Region, calculating the Interconnection minimum Frequency Response and monitoring the actual Frequency Response of the Interconnection.

Likes 0	
Dislikes 0	

Response

Yvonne McMackin - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes
Document Name	
Comment	
BAs can have large changes in their generation mix from year to year. A large generator could be removed from a BA either by shutting down of being placed in another BA while continuing to operate. In this case, the FRO for the BA in a particular year could be artificially high for one BA and artificially low for another due to the delay involved to determine the FRO. If a frequency standard examined generator response rather than a measure related to a BA, this inequity should not occur.	
Likes 0	
Dislikes 0	
Response	

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
The current BAL-003-1.1 standard has the Balancing Authority reviewing and analyzing event data that was taken over a year ago to see if the Balancing Authority met the minimum requirement. After reviewing and analyzing the events, if the Balancing Authority discovers it did not meet the standard, it is too late for the Balancing Authority to try and resolve the issue. If the Balancing Authority had the chance to correct the issue, this would increase reliability of the grid and give the Balancing Authority another chance to pass the standard. The current purpose of the BAL-003-1.1 standard is to maintain Interconnection Frequency by arresting frequency deviations, and this can only be done if the standard requires real time analysis. Real time analysis and requirements would allow all parties to review and adjust how their units will respond to the next event.	
Likes 0	
Dislikes 0	
Response	

James Ramos - Turlock Irrigation District - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Although frequency response is required and actually provided in real-time to address resource contingencies within the interconnection, the current BAL-003-1.1 does not measure at the time of the event the ability to provide frequency response nor does it identify the parties that may have the ability	

to respond under the current real-time topology (transmission, generation and demand). Utilizing two year old data to allocate the Interconnection Frequency Response Obligation fails to recognize real-time conditions and how topologies may change.

Likes 0	
Dislikes 0	

Response

Antonio Franco - Gridforce Energy Management, LLC - NA - Not Applicable - WECC

Answer	Yes
Document Name	

Comment

Griforce Energy Management agrees and supports the SAR. The allocation of FRO should happen real time based on system conditions and available resources to support potential losses of resource output. Therefore, BA's actual FRO should be a dynamic target based on the BA's real time generation plus load during a BAL-003 event selected by the NERC FWG.

Likes 0	
Dislikes 0	

Response

Theresa Rakowsky - Puget Sound Energy, Inc. - 1,3,5

Answer	Yes
Document Name	

Comment

Puget Sound Energy (PSE) fully supports the SAR for Project 2017-01 and proposed revisions. FERC Form 714 does not accurately show the state of the interconnection because it uses historical data that is over 2-years old; data should be current or at least within the last (rolling) 12 month period.

Likes 0	
Dislikes 0	

Response

Dori Quam - NorthWestern Energy - 1 - WECC

Answer	Yes
Document Name	

Comment

Frequency response is required and provided during real-time resource contingencies within the interconnection. Currently BAL-003-1.1 does not measure at the time of the event the ability to provide frequency response nor does it identify the parties that may have the ability to respond under the current real-time topology (transmission, generation and demand). Utilizing two-year-old data to allocate the Interconnection Frequency Response Obligation fails to recognize real-time conditions and how topologies may change. The SAR to modify BAL-003-1.1 should specify criteria and design calculations for the real-time measurement of frequency performance.

Likes 0	
Dislikes 0	

Response

Casey Johnston - Concerned Electrical Engineer with 40 yrs in Electrical Industry - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	

Comment
Frequency response is required and provided during real-time resource contingencies within the interconnection. Currently BAL-003-1.1 does not measure at the time of the event the ability to provide frequency response nor does it identify the parties that may have the ability to respond under the current real-time topology (transmission, generation and demand). Utilizing two year old data to allocate the Interconnection Frequency Response Obligation fails to recognize real-time conditions and how topologies may change. The SAR to modify BAL-003-1.1 should specify criteria and design calculations for the real-time measurement of frequency performance.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF, Group Name Consumers Energy Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	

Document Name	
Comment	

BPA is a member of the WFRSG and supports the WFRSG SAR. There are many things in the current BAL-003 standard that need to be changed.

BPA does not know how to interpret this question. Mention of the real time measure of frequency performance does not seem to fit with the allocation of the IFRO. BPA does see issues in the two year old data used to allocate responsibility. BPA encourages the Standards Drafting Team to consider revising how the IFRO is allocated.

BPA takes issue in how this question is presented. BPA did not see a specific proposed revision in the above question, and therefore finds it hard to answer either yes or no. Instead BPA was forced to make its own assumptions regarding what the question pertained to. Therefore we cannot provide specific language, because no specific revision was proposed. In general, BPA does support the drafting team considering a revision to the standard to reflect what is required for real-time reliability.

Likes 0	
Dislikes 0	
Response	

3. The SAR proposes to modify the current BAL-003-1.1 standard to eliminate the incorrect signals to the market for arbitrary pricing and conditions. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

Thomas Foltz - AEP - 3,5	
Answer	No
Document Name	
Comment	
AEP believes that a Reliability Standard is adopted to sustain or improve reliability, and not to support the energy markets. Discussion of commercial considerations is outside the scope of a Reliability Standard and should not be matters of discussion within standards development.	
Likes 0	
Dislikes 0	
Response	

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
This is a Balancing Authority control issue and should not be applied to a NERC Standard. Should not this be addressed in BAL-001?	
Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
The information in the SAR and the background document do not provide enough information to clearly understand the intent of the perceived problem or a proposed solution to it.	
Likes 0	

Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
This is a reliability standard. It is not appropriate to discuss the Market Pricing here.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
AZPS respectfully asserts that market issues and/or distortions are not appropriate justifications for the revision of reliability standards. While a reliability standard should not interfere with market principles, they are not the appropriate vehicle to "cure" market issues. Such issues are often market-specific and, therefore, are better addressed within the stakeholder processes of the Market Operator or with the FERC. Additionally, AZPS notes that the SAR is unclear about the specific market distortions being caused by BAL-003-1, its intent or method for correction, and how the proposed revisions would correct the identified distortions. AZPS has not observed any market-related distortions as a result of BAL-003-1 and, without adequate and sufficient information and justification, cannot support revision.	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
The SAR does not provide details of the incorrect market signals to determine if this is needed or required.	

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
The IESO does not agree with linking NERC standards to market mechanisms/decisions. NERC standards should be written only to meet reliability objectives.	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	No
Document Name	
Comment	
PJM does not believe it is appropriate for NERC to address market signals or pricing.	
Likes 0	
Dislikes 0	
Response	
Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - SERC,RF, Group Name ISO Standards Review Committee	
Answer	No
Document Name	
Comment	
The SRC does not agree that this NERC standard is or should be linked to Market decisions.	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE supports eliminating arbitrary estimates and non-comparable formulas where appropriate. The SDT will need to clearly demonstrate the specific aspects of the current Standard that result in incorrect signals to provide primary frequency response, as well as other unintended consequences stemming from the current Standard design. Texas RE looks forward to reviewing and carefully considering this specific evidence in the Standard Development process.	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 2,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	No
Document Name	
Comment	
While the SAR appears to propose some kind of modifications on market signals, there is insufficient information in the SAR and no information at all in the supporting materials to understand what is being proposed to be addressed or modified. In any case, the market signal issue should only be addressed in a SAR if it is directly connected to reliability. Reliability standards should address reliability issues; they are not the appropriate vehicle for addressing market issues.	
Likes 0	
Dislikes 0	
Response	
Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	
Standards exist and should be written to improve reliability and not to evaluate commercial considerations. The Standard drafting team should simply	

ensure that what is written can achieve a reliability benefit in excess of the costs needed to achieve that benefit.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
It's not clear how this can be accomplished nor why a market rule should not be developed instead of altering a reliability requirement. We encourage the drafting team to consider the previous NERC Advisory on Generator Frequency Response of 2015 and the Reliability Guideline on Primary Frequency Control. If generator owners will be required to operate with defined droop and deadband, guidance on correct droop and deadband for each type of plant would be appreciated. The 2015 Advisory did not differentiate between fossil, nuclear, combined cycle, etc; there was, however, some guidance in the Reliability Guideline. We also request the drafting team to consider the limitations of nuclear units to provide frequency response to under-frequency events.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We caution the reference to arbitrary market pricing and elimination of market signals in the reliability standard development process. NERC Reliability Standards focus on developing a results-based approach regarding the performance and capabilities of registered entities and their operations, planning, and risk management activities regarding the bulk power system. We disagree that it is NERC regulations that drive market signals, and we believe such references should be removed from the SAR.	
Likes 0	
Dislikes 0	
Response	
Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	

Answer	No
Document Name	
Comment	

Tacoma Power believes that although Balancing Authorities do not inherently have frequency responsive capabilities, these capabilities can be acquired via contractual agreements and market products. It appears the current market is not arbitrary. FERC should consider providing direction as to who should be compensating BAs for acquiring frequency response products necessary to meet this standard. However, Tacoma suggests that NERC review the standard for alignment between desired frequency performance and existing performance measurement.

Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed ISO-NE

Answer	No
Document Name	
Comment	

NPCC does not agree with linking NERC standards to market mechanisms/decisions. NERC standards should be written only to meet reliability objectives.

Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	
Comment	

SRP supports the comments submitted by AZPS in response to question 3.

Likes 0	
Dislikes 0	
Response	

Casey Johnston - Concerned Electrical Engineer with 40 yrs in Electrical Industry - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	
Comment	

BAL-003 should not create a new market for a reliability product that currently exists. Under the current version of BAL-003-1.1 a GO/GOP can charge customers twice for the same capacity needed for reliability purposes. The difference between the capacity products is simply a time measurement period. For example, 10 MW of Contingency Spinning Reserves can also be sold as FRR. This is the same product and capacity but the customer pays twice.

Likes 0	
Dislikes 0	
Response	

Dori Quam - NorthWestern Energy - 1 - WECC

Answer	Yes
Document Name	
Comment	

BAL-003 should not create a new market for a reliability product that currently exists. Under the current version of BAL-003-1.1 a GO/GOP can charge customers twice for the same capacity needed for reliability purposes. The difference between the capacity products is simply a time measurement period. For example, 10 MW of Contingency Spinning Reserves can also be sold as FRR. This is the same product and capacity, but the customer pays twice.

Likes 0	
Dislikes 0	
Response	

Theresa Rakowsky - Puget Sound Energy, Inc. - 1,3,5

Answer	Yes
Document Name	
Comment	

The current standard is overly burdensome on Balancing Authorities with compliance obligations to maintain reliability because it provides no recourse if a Generator Owner (GO) does not implement and provide frequency response capabilities. GOs are an inherent part of the Bulk Electric System and are the best resource to support immediate frequency response needs on the Interconnection.

Likes 0	

Dislikes 0	
Response	
James Ramos - Turlock Irrigation District - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
BAL-003 should drive market signals that reflect what is truly needed for reliability, to ensure 100% coverage for the interconnection through equipment capability, capacity, and dispatch, and provide correct signals to the parties with the ability to deliver real-time frequency response.	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
BAL-003-1.1 should drive market signals that reflect what is truly needed for reliability, to ensure 100% coverage for the interconnection through equipment capability, capacity, dispatch, and provide correct signals to the parties with the ability to deliver real-time frequency response. The conditions that have been set in the standard are arbitrary, especially in regards to when, how, and where you need them.	
Likes 0	
Dislikes 0	
Response	
Yvonne McMackin - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes
Document Name	
Comment	
Grant PUD would like to stress there is **nothing arbitrary** about the pricing that has occurred for the supply of frequency response. When Grant PUD has determined prices to use in responding to RFPs for frequency response, we have carefully considered the risks involved and the finite supply available. The fact that RFPs are generally used by a purchaser indicates pricing is not arbitrary.	

Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BAL-003 should drive market signals that reflect what is truly needed for reliability, to ensure 100% coverage for the interconnection through equipment capability, capacity, and dispatch, and provide correct signals to the parties with the ability to deliver real-time frequency response.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
While PacifiCorp does not believe the pricing of FRM in and of itself has been arbitrary, it is clear that the calculation and allocation of FRM is inaccurate and arbitrary, and therefore has created an arbitrary product for which BAA's have had to create prices, buy and sell. Therefore PacifiCorp strongly agrees that the mechanisms behind these calculations and allocations need to be addressed.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	

A Reliability Standard does not address market issues, but at the same time, a Reliability Standard should establish a performance requirement that supports system reliability. “Meeting the requirement” should enhance reliability, which is the goal of the standard. R1 measures the median performance of a BA over a 12 month period. Every BA in the interconnection could fail to provide FRR for a single event, the interconnection could suffer underfrequency load shedding and eventual break up, and each BA would still pass R1 if it met the median requirement for the measurement year. It seems that BAL-003-1 does not enhance system reliability, but could encourage operational practices that could degrade system reliability. If a BA has passed 13 events (assuming 25 for the year), after the 13th pass, the BA could alter its generation operations minimizing primary frequency response, still passing for the year, but degrading overall reliability for a portion of the year.

Likes 0	
Dislikes 0	

Response

Angela Gaines - Portland General Electric Co. - 1,3,5,6

Answer	Yes
Document Name	

Comment

BAL-003 should provide correct market signals to those parties who are able to deliver real-time frequency response and that reflect what is actually needed to ensure complete coverage for the Interconnection through equipment capability, capacity and dispatch.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1,6

Answer	Yes
Document Name	

Comment

BAL-003 should drive market signals that reflect what is truly needed for reliability, to ensure 100% coverage for the interconnection through equipment capability, capacity, and dispatch, and provide correct signals to the parties with the ability to deliver real-time frequency response. Purchase and Sale of Frequency Response does nothing to maintain or improve the Frequency Response of the bulk system, instead it drives a market to equitably distribute the actual historical Frequency Response between all entities in an interconnection.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
The SPP Standards Review Group has a concern that the proposed modification could create Marketing issues outside the scope of the Standards Drafting Team.	
Likes 0	
Dislikes 0	
Response	
Jeff Rehfeld - NaturEner USA, LLC - 5 - WECC	
Answer	Yes
Document Name	
Comment	
Comments: BAL-003 should drive market signals that reflect what is truly needed for reliability, to ensure 100% coverage for the interconnection through equipment capability, capacity, and dispatch, and provide correct signals to the parties with the ability to deliver real-time frequency response, each subject to and mindful of the considerations raised by Commenter in the second paragraph to its Comments to Question 1 above.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
If using interchange as a proxy for frequency response contains inaccurate signals then system reliability could be negatively impacted. Mandatory NERC standards that carry penalties must be accurate and cannot negatively impact system reliability.	
Likes 0	
Dislikes 0	
Response	

Antonio Franco - Gridforce Energy Management, LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF, Group Name Consumers Energy Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	

Answer	
Document Name	
Comment	

BPA is a member of the WFRSG and supports the WFRSG SAR. There are many things in the current BAL-003 standard that need to be changed.

A market has been created due to this standard; however, BPA sees no market signals in the standard. BPA is not sure what is meant by arbitrary prices. On the subject of markets, BPA does have concerns looking into the future, with the median FRM being used for compliance and driving a market based on median performance.

BPA takes issue in how this question is presented. BPA did not see a specific proposed revision in the above question, and therefore finds it hard to answer either yes or no. Instead BPA was forced to make its own assumptions regarding what the question pertained to. Therefore we cannot provide specific language, because no specific revision was proposed. In general, BPA does support the drafting team considering a revision to the standard to reflect what is required for real-time reliability.

Likes 0	
Dislikes 0	
Response	

4. Based on the scope of the Phase II section of the SAR, do you have any other comments for drafting team consideration?	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF, Group Name Consumers Energy Company	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed ISO-NE	
Answer	Yes
Document Name	
Comment	

NPCC supports the original SAR (proposed by the NERC RS and posted in June/July of this year) to correct inappropriate assumptions in the current standard. If this SAR is intended to replace or supplement the original SAR, then the following process issues arise:

- There lacks clarity as to what may happen to the first SAR. If the intent is to proceed with the first phase per the first SAR, then this currently posted SAR should be submitted as an addendum to the first SAR. It is confusing, and inappropriate, to post 2 SARs addressing in whole or in part of the same proposed project.
- Posting this SAR for industry comment may be premature, given that the first phase hasn't yet been completed and hence changes to the existing BAL-003 are not known. Some of the changes eventually embraced by the industry, adopted by the BOT and approved by regulatory authorities may address part or all of the reliability needs intended by the second phase.

The SAR lacks evidence of reliability needs/benefits to justify the second phase tasks.

Likes 0	
Dislikes 0	
Response	

Jeff Rehfeld - NaturEner USA, LLC - 5 - WECC	
Answer	Yes
Document Name	
Comment	

Comments: The SAR identified several issues regarding the FRM as the sole measure of frequency response performance. The SAR stated: "The standard must be able to measure all types of Frequency Response and credit the providers. The current standard does not reflect different types of Frequency Response and the timing of such response." Please add the issue regarding the basis of measuring frequency response performance to this ballot.

Likes 0	
Dislikes 0	

Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	

1. We reiterate from our previous comments that the scope identified within the SAR is too broad and appears to have no definite deadlines. The current proposal to split its activities into two separate phases is problematic, as the second phase is likely to result in a field trial. Will this delay the regulatory approval activities associated with the first phase? What happens if the first phase results in the issuance of FERC directives that will then need to be addressed in a third phase?
2. The previous SAR identified the possibility of relocating the standard's Attachment A to a NERC Operating Committee-approved reference document or Reliability Guideline. The proposed SAR does not clarify how this information will be treated in the future.
3. The SAR should be expanded to clarify frequency-related definitions listed within the NERC Glossary. For example, Frequency Response has two separate meanings in the NERC Glossary.
4. We thank you for this opportunity to provide these comments.

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

The SPP Standards Review Group has a concern that the introduction of Phase II at the current state presents confusion on what goals should be accomplished by both SAR(s). From our perspective, we feel that all goals haven't been met with reference to the first SAR and the project shouldn't move forward to the second phase until all Phase I goals have been addressed and resolved.

Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	

The SAR identified several issues regarding the FRM as the sole measure of frequency response performance. The SAR stated: "The standard must be able to measure all types of Frequency Response and credit the providers. The current standard does not reflect different types of Frequency Response and the timing of such response." Please add the issue regarding the basis of measuring frequency response performance to this ballot.

Joint Owned Units, Pseudo Ties, and Dynamic Schedules that require special consideration when using Net Actual Interchange to determine performance, the Standards Drafting Team should be sure to carefully consider their impacts.

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer	Yes
Document Name	

Comment

Xcel Energy has concerns that the inclusion of measurements of all types of frequency response may over complicate this standard and become difficult to comply with and enforce.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

BPA would like to ensure that NERC considers additional points in the SAR that do not seem to be addressed in the previous questions. These include:

- **Real time reliability and the median measure:** BPA thinks that the BAL-003 standard should be modified to address real - time reliability. By basing performance on the median of events, reliability is not assured. The median has only worked to this point because interconnections have shown historically adequate response. If response declined, and better performance was needed, an increase to the IFRO alone would not assure reliability. Even if the IFRO was increased, there is nothing to dictate that capability must be online for every event to meet the standard. It is possible that that raising the IFRO would only raise the overall median response of the interconnection, while extreme low responses on the interconnection remain. One solution to this is to move to a rolling average of performance as is in the ERCOT BAL-001-TRE standard. This would place more pressure on responsible entities to incentivize performance for every event.

- **Evaluate how frequency response is measured:** Through work done in the WFRSG BPA is aware of many issues related to using NIA in an FRM calculation. These issues are laid out in the technical document supplied by the WFRSG. As well as the issue with the calculation of the FRM, BPA does not think that the FRM should be the sole measure of frequency response. Only by comparing actual generator performance to NIA can the true response in the BA be determined. BPA also encourages the SDT to evaluate the A to B ratio, compared to a hurdle and bench measurement at the generator level. Equipment can be designed many ways to meet a 20-52 second performance window and do very little for the initial arrest of frequency. Both hurdle and bench performances are important for adequate frequency response.

- **The standard only implies a needed capacity:** Frequency response requires both capability and capacity on a resource. This needed capacity is only implied through the standard. BPA believes that more study should be directed at determining the needed frequency response capacity on an interconnection. This capacity should be built into the standard. Without this, BA's in WECC could easily meet the standard by only holding 0.1 Hz worth of frequency response capacity. This is because the large majority of events in WECC are less than 0.1 Hz A to B frequency deviation.
- **Event Selection:** Several aspects of BAL-003's event selection and response measurement process may perversely reward poor performance and penalize proper performance. BPA encourages the SDT to evaluate the issues presented in the WFRSG technical document related to these issues.
- **Allocation of the IFRO:** BPA encourages the standard drafting team to review the issues laid out in the WFRSG technical document related to the allocation of the IFRO.

Likes 0	
Dislikes 0	

Response

Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Chelan PUD

Answer	Yes
Document Name	

Comment

The added cost of the benefits of the SAR should be weighed against the actual benefits of the SAR. This evaluation should include the cost of the time associated with any testing, etc. to meet the added requirements of the SAR.

Likes 0	
Dislikes 0	

Response

Shelby Wade - PPL - Louisville Gas and Electric Co. - 2,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company

Answer	Yes
Document Name	

Comment

The BAL-003-1.1 SAR technical document focuses on operating characteristics and issues which are largely unique to the Western Interconnection. As stated in the document, the Western Interconnection contains the only FRSG in North America. Although Phase 1 of the SAR could improve the standard (i.e., the calculation of IFRO), it seems the concerns addressed in Phase 2 of the SAR are primarily applicable to the Western Interconnection and its unique FRSG. This suggests a regional standard applicable to the Western Interconnection and its FRSG would be more appropriate for the

issues to be addressed in Phase 2.

Likes 0	
Dislikes 0	

Response
David Ramkalawan - Ontario Power Generation Inc. - 5

Answer	Yes
Document Name	

Comment
The compliance obligations stemming from the newly revised BAL-003 standard should be coordinated with the UFLS to ensure the adequate frequency response occurs to rapid arrest the frequency decline and prevent the underfrequency load shedding.

Likes 0	
Dislikes 0	

Response
Angela Gaines - Portland General Electric Co. - 1,3,5,6

Answer	Yes
Document Name	

Comment
Among other issues identified in the SAR regarding the use of FRM as the sole measure of frequency response performance, the SAR stated: “The standard must be able to measure all types of Frequency Response and credit the providers. The current standard does not reflect different types of Frequency Response and the timing of such response.” PGE requests the addition of this issue to the ballot.

Likes 0	
Dislikes 0	

Response
Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - SERC,RF, Group Name ISO Standards Review Committee

Answer	Yes
Document Name	

Comment

The SRC supports the original SAR as proposed to correct inappropriate assumptions in the current standard but does not support this revision of that SAR.

Further the SRC contends:

- There is no explanation in this revision of what to do with the original SAR. If the intent is to proceed with the first phase per the first SAR, then this currently posted SAR should be submitted as an addendum to the first SAR. It is confusing, and inappropriate, to post two SARs addressing in whole or in part of the same proposed tasks.

- Posting this SAR for industry comments may be premature, given that the first phase hasn't been completed and hence changes to the existing BAL-003 are not known. Some of the changes eventually embraced by the industry, adopted by the BoT and approved by regulatory authorities may address part or all of the reliability needs intended by this second SAR.

- The SAR lack evidence of reliability needs/benefits to justify the second phase tasks.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1,3,5

Answer	Yes
Document Name	

Comment

The standard should consider performance in the A to C time period. The present measurement period is A and B. The transition period is not measured. The Western Interconnection is seeing a changing resource mix in a portion of the interconnection. The effects of this change are unknown, and are not being carried out in a planned manner. There is a notable change in the Rate of Change of Frequency (ROCOF) for some events, resulting in faster and deeper A to C frequency changes than have been observed in the past. At some point, it will be necessary for System Operators to have awareness of primary frequency resources available in real time to meet a loss in resources and stabilize frequency. Primary frequency response can be provided by many resources. An awareness of its availability and location enhances reliable system operations.

Likes 0	
Dislikes 0	

Response

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF

Answer	Yes
Document Name	

Comment

PJM believes the effort should continue on the original SAR submitted by the NERC RS. This will offer the opportunity to rectify the existing defects in the current BAL-003 standard and provide an accurate baseline performance of frequency response among the BAAs and Interconnections.

PJM does see merit in some of the technical arguments presented in the supplemental SAR; namely exploring a capability requirement for all generators and real-time monitoring. PJM would support these issues being worked following completion of the existing SAR, in whatever capacity deemed appropriate (modification to BAL-003, modification/creation of a different standard).

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

The IESO supports the original SAR (proposed by the NERC RS and posted in June/July of this year) to correct inappropriate assumptions in the current standard. If this SAR is intended to replace or supplement the original SAR, then the following process issues arise:

- There lacks clarity as to what may happen to the first SAR. If the intent is to proceed with the first phase per the first SAR, then this currently posted SAR should be submitted as an addendum to the first SAR. It is confusing, and inappropriate, to post 2 SARs addressing in whole or in part of the same proposed project.
- Posting this SAR for industry comment may be premature, given that the first phase hasn't yet been completed and hence changes to the existing BAL-003 are not known. Some of the changes eventually embraced by the industry, adopted by the BoT and approved by regulatory authorities may address part or all of the reliability needs intended by the second phase.
- The SAR lacks evidence of reliability needs/benefits to justify the second phase tasks.

Likes 0	
Dislikes 0	

Response

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	Yes
Document Name	

Comment

The phased approach needs to be two distinctive processes. We should not delay the correction proposed in phase I to incorporate any proposed

modifications that are noted in phase II. This SAR needs to address only the changes required after modifications of Phase I are complete.	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT takes no position on this SAR; however, if any issues from the 2nd SAR are to be explored further, ERCOT recommends they be addressed by the existing standard drafting team under the existing project rather than expanded into another SDT/project.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
AZPS is concerned about the clear intent to cure market issues through revisions to reliability standards. It further is concerned about the lack of justification, specificity, and supporting technical information or data provided in the SAR. Such ambiguity does not provide registered entities with the necessary data to form rigorous, comprehensive comments.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	

The stated intent of the standard is to assure adequate frequency response for the interconnection to avoid under frequency load shedding for large events. As currently written this standard:

{C}1) Does not require any frequency response for large events

{C}2) Could allow multiple under frequency load shedding events each year without any individual entity failing compliance

{C}3) Contains no requirement to maintain frequency responsive reserves

{C}4) Creates an inaccurate frequency response measurement, and then allocates that measurement to entities that have no authority to require frequency response

{C}5) Tricks BAA's into thinking they are providing frequency response due to the "FRM" calculation method

Because of this PacifiCorp believes the standard falls short of meeting its stated intent, and a thorough review is warranted.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	Yes
Document Name	

Comment

A better approach for this SAR (phase II) would be to separate it from the existing tightly scoped SAR. This allows the flexibility to potentially develop a separate standard directed toward the more appropriate FM entities.

Likes 0	
Dislikes 0	

Response

Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC

Answer	Yes
Document Name	

Comment

The SAR identified several issues regarding the FRM as the sole measure of frequency response performance. The SAR stated: "The standard must be able to measure all types of Frequency Response and credit the providers. The current standard does not reflect different types of Frequency Response and the timing of such response."

The use of "Net Actual Interchange" may not be the best dataset for FRM. When a frequency deviation occurs due to loss of a large generator or RAS actions, generator governors respond automatically to the resulting drop in frequency. If a BAA is electrically between a large resource providing frequency response and the lost generation, transmission flows can increase on the intermediary BAA's system. As transmission flows increase, transmission line losses increase as well. These losses appear as increased load on the intermediary BAA's system, which can in turn affect apparent FRM performance. In some instances, even though the BAA's generation and load response is appropriate, the losses incurred due to neighboring generator response can overwhelm the BAAs actual FRM.

Likes 0	
Dislikes 0	

Response

Yvonne McMackin - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6

Answer	Yes
Document Name	

Comment

Grant PUD is not convinced that measuring response in the 10-20 second time frame is better than using the 20-52 second timeframe. Careful evaluation needs to be performed to determine the ideal timeframe to measure response. The best timeframe to measure response may depend on the method chosen to quantify the response.

Likes 0	
Dislikes 0	

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer	Yes
Document Name	

Comment

The Phase II section of the SAR identifies the most important changes that need to occur for the BAL-003-1.1 standard to truly address reliability. Phase II addresses the need for using real-time measurements of frequency performance, the need to update the applicability of the standard, and the

need for correct market signals.	
Likes 0	
Dislikes 0	
Response	
James Ramos - Turlock Irrigation District - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
The current BAL-003-1.1 standard does not reflect different types of Frequency Response and the timing of such response." Please add the issue regarding the basis of measuring frequency response performance to this ballot.	
Likes 0	
Dislikes 0	
Response	
Antonio Franco - Gridforce Energy Management, LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Gridrforce Energy Management would like to request the drafting team to consider the following: - Allocating FRO based on BA's real time generation plus load (similar to the way CRO is calculated in the Western Interconnection). - Re-evaluate and establish a more realistic window for calculating Primary Frequency Response (currently set between T+20 to T+52 seconds). - Frequency Bias Setting is used by Balancing Authorities for regulation or secondary frequency response purposes. Therefore, FBS should not be calculated solely based on primary frequency response performance, which only generator governors and load are capable of prividing to arrest and stabilize system frequency.	
Likes 0	
Dislikes 0	
Response	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1,3,5	

Answer	Yes
Document Name	
Comment	

PSE considers BAL-003-1.1 to be unduly discriminatory. To address reliability, BAL-003-1.1 should be modified to impose requirements on individual generating owners' facilities and not burden Balancing Authorities with the cost of 1) procuring frequency response in the market or 2) incurring extensive administrative legal costs through separate, individual Generation Interconnection Agreements.

Likes 0	
Dislikes 0	
Response	

Dori Quam - NorthWestern Energy - 1 - WECC

Answer	Yes
Document Name	
Comment	

The SAR identified several issues regarding the FRM as the sole measure of frequency response performance. The SAR stated: "The standard must be able to measure all types of Frequency Response and credit the providers. The current standard does not reflect different types of Frequency Response and the timing of such response." Please add the issue regarding the basis of measuring frequency response performance to this ballot. The SAR for BAL-003-1.1 should specify and require strict parameters for the selection of FRR events used for compliance requirements. This would be similar to the BAL-002 parameters used for DCS event selection.

Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 3,5

Answer	Yes
Document Name	
Comment	

AEP is not in agreement with the Phase II content of the BAL-003 SAR. AEP suggests the SDT recommend that the content of Phase II SAR for BAL-003 instead be considered for a ***regional*** Reliability Standard based on the examples provided in the supporting document "Standards Authorization Request Revision to BAL-003-1.1 Frequency Response and Frequency Bias Setting June 28, 2017", since the other interconnections are not experiencing the issues brought forth.

Likes 0	
Dislikes 0	
Response	
Casey Johnston - Concerned Electrical Engineer with 40 yrs in Electrical Industry - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
The SAR identified several issues regarding the FRM as the sole measure of frequency response performance. The SAR stated: “The standard must be able to measure all types of Frequency Response and credit the providers. The current standard does not reflect different types of Frequency Response and the timing of such response.” Please add the issue regarding the basis of measuring frequency response performance to this ballot. The SAR for BAL-003-1.1 should specify and require strict parameters for the selection of FRR events used for compliance requirements. This would be similar to the BAL-002 parameters used for DCS event selection. In my professional experience, BAL-003-1.1 is the most poorly written and is the only retrospective standard, since the creation of the current NERC Mandatory standard system in 2006. The Standard needs to be rewritten and the deficiencies corrected	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE requests the SDT consider adding language to the standard to address the process for exclusions in Attachment 1, including the entity responsible for granting exclusions and the documentation required (such as corrective action plans) when requesting an exclusion.	
Likes 0	
Dislikes 0	
Response	

Consideration of Comments

Project Name:	2017-01 Modifications to BAL-003-1.1 | Standards Authorization Request
Comment Period Start Date:	11/2/2017
Comment Period End Date:	12/1/2017
Associated Ballots:	

There were 42 sets of responses, including comments from approximately 115 different people from approximately 75 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Senior Director of Standards and Education, Howard Gugel (via email) or at (404) 446-9693.

Questions

1. The SAR proposes to modify the current BAL-003-1.1 standard to reflect the correct applicable entity that controls and provides frequency response, to reflect comparability among the applicable entities, and to eliminate arbitrary allocation of responsibility. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

Based on the responses to this question, the SAR has been revised to review the applicable entities to determine if another entity might be appropriate as having applicability. The Standard Drafting Team will likely focus on determining if an additional requirement might be needed as opposed to replacing any of the current requirements.

2. The SAR proposes to modify the current BAL-003-1.1 standard to allow for real-time measurement of frequency performance obligation instead of a two year old allocation. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

There was some underlying confusion by commenters in interpreting this question, which deals with the allocation of the Frequency Response Obligation (FRO) among Balancing Authorities (BA) in an Interconnection. The current standard assigns a fixed FRO based on the BAs' share of Interconnection load and generation as determined in the last published FERC 714 data. The NWPP SAR proposes a time varying FRO based on current topology.

Poll tallies for the proposed change were as follows:

- Yes (24). Four of the affirmative responses appeared to misunderstand the question as they state support for a real-time measurement of performance as opposed to the allocation of the FRO.
- No (15)
- No Answer (1)

Those voting for the modification were predominantly from the Western Interconnection. It is recommended the standard drafting team evaluate the feasibility of a time-varying FRO as well as whether the time-varying approach should be applicable to all Interconnections. Those voting against the modification felt that the current FRO allocation works and were concerned with the added complexity to evaluating performance.

Other comments include:

- Behind the meter generation should be factored into a time-varying FRO.
- Evaluation of the time varying FRO should be a later stage effort.

3. The SAR proposes to modify the current BAL-003-1.1 standard to eliminate the incorrect signals to the market for arbitrary pricing and conditions. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

4. Based on the scope of the Phase II section of the SAR, do you have any other comments for drafting team consideration?

The Industry Segments are:
1 — Transmission Owners
2 — RTOs, ISOs

3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
PJM Interconnection, L.L.C.	Albert DiCaprio	2	RF,SERC	ISO Standards Review Committee	Charles Yeung	SPP	2	SPP RE
					Ben Li	IESO	2	NPCC
					Mark Holman	PJM	2	RF
					Kathleen Goodman	ISONE	2	NPCC
					Greg Campoli	NYISO	2	NPCC
					Terry Bilke	MISO	2	RF
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Shari Heino	Brazos Electric Power	1,5	Texas RE

						Cooperative, Inc.		
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Mike Brytowski	Great River Energy	1,3,5,6	MRO
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Mark Ringhausen	Old Dominion Electric Cooperative	4	SERC
					Mark Ringhausen	Old Dominion Electric Cooperative	3,4	SERC
					Ryan Strom	Buckeye Power, Inc.	5	RF
					Ryan Strom	Buckeye Power, Inc.	4	RF
					Patrick Woods	East Kentucky Power Cooperative	1,3	SERC
Duke Energy		1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF

	Colby Bellville				Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
	Janis Weddle	1,3,5,6		Chelan PUD	Haley Sousa	Public Utility District No. 1	5	WECC

Public Utility District No. 1 of Chelan County						of Chelan County		
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Jeff Kimbell	Public Utility District No. 1 of Chelan County	1	WECC
					Janis Weddle	Public Utility District No. 1 of Chelan County	6	WECC
Consumers Energy Company	Jeanne Kurzynowski	1,3,4,5	RF	Consumers Energy Company	Jeanne Kurzynowski	Consumers Energy Company	1,3,4,5	RF
					Jim Anderson	Consumers Energy Company	1	RF
					Karl Blaszkowski	Consumers Energy Company	3	RF
					Theresa Martinez	Consumers Energy Company	4	RF

					David Greyerbiehl	Consumers Energy Company	5	RF
Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc	1	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC
					William Shultz	Southern Company Generation	5	SERC
Manitoba Hydro	Mike Smith	1,3,5,6		Manitoba Hydro	Yuguang Xiao	Manitoba Hydro	5	MRO
					Karim Abdel-Hadi	Manitoba Hydro	3	MRO
					Blair Mukanik	Manitoba Hydro	6	MRO
					Mike Smith	Manitoba Hydro	1	MRO
	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion	Guy V. Zito	Northeast Power	10	NPCC

Northeast Power Coordinating Council				NextERA Con-Ed ISO-NE		Coordinating Council		
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC

					Laura Mcleod	NB Power	1	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					Greg Campoli	NYISO	2	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Brent Hebert	Northeast Texas	5	SPP RE

						Electric Cooperative - HCCP		
					Louis Guidry	Cleco Corporation	1,3,5,6	SPP RE
					Robert Hirchak	Cleco Corporation	6	SPP RE
PPL - Louisville Gas and Electric Co.	Shelby Wade	2,5,6	RF,SERC	Louisville Gas and Electric Company and Kentucky Utilities Company	Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					Dan Wilson	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC

1. The SAR proposes to modify the current BAL-003-1.1 standard to reflect the correct applicable entity that controls and provides frequency response, to reflect comparability among the applicable entities, and to eliminate arbitrary allocation of responsibility. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

Thomas Foltz - AEP - 3,5	
Answer	No
Document Name	
Comment	
AEP does not believe that BAL-003 -1.1 requires the BA to be directly responsible for providing primary frequency response. Rather, it sets the expectations for the performance of the BA in recovering from a frequency event with secondary frequency response through AGC. In our opinion, the allocation of responsibility is not arbitrarily assigned to the BA, but rather correctly assigned to the BA. Having said that, it seems the standard's Purpose statement is somewhat out of step with the requirements themselves and perhaps should be revised to better align with those requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SAR drafting team will recommend the Standard Drafting Team take into consideration these suggestions when evaluating modifications to the standard.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

The apparent implication is that GOPs have responsibility for primary frequency response (PFR). Even for PFR, coordination of frequency response capability lies with BAs or collections of BAs, not with individual resources. For example, a BA may have ample frequency responsive resources available, but if it chooses not to have enough of them online with adequate headroom, frequency response will not be adequate. A standard to require resources to have frequency responsive capability may have merit, but combining that with the responsibilities of BAs may very likely lead to unneeded confusion. The background document cites ERCOT's BAL-001-TRE-1 as a model, but it is a separate standard, not a replacement for BAL-003. Regarding comparability and allocation, we do not agree that the difference in resource mix or the amount of native BA load warrant a difference in treatment. The mechanism currently employed parallels the basis for NERC and RE funding allocation and has essentially the same time lag.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process, if it is determined that such additions are warranted.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
AZPS can support exploring whether additional functional entities should be addressed in the applicability section of the standard and/or with targeted requirements. However, AZPS cautions against creating redundant requirements in these reliability standards as FERC is currently proposing changes in the Open Access Transmission Tariffs. Finally, AZPS cannot outright support a need for a revision without evidence of a study or evaluation of the need to add additional applicable entities and without indication regarding the entities to which any associated revision would be directed.	

Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
We do agree with the concept of properly allocating responsibility. The phased approach needs to be two distinctive processes. We should not delay the correction proposed in phase I to incorporate any proposed modifications that are noted in phase II. This SAR needs to address only the changes required after modifications of Phase I are complete.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The SAR will allow for two phases to be used.	
Leonard Kula - Independent Electricity System Operator – 2	
Answer	No
Document Name	
Comment	

The IESO believes that the Balancing Authority is the appropriate entity responsible for assuring that its ACE performance is compliant with the current BAL performance requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	No
Document Name	
Comment	
PJM supports the exploration of a capability requirement for GOPs to provide primary frequency response. However, PJM sees this as supplemental, not a replacement of the BA requirement. PJM does not believe it is appropriate to reflect comparability among applicable entities. A BAs load response, or mix and type of generation should not play a role in the primary frequency response allocation	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted.	
Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - SERC,RF, Group Name ISO Standards Review Committee	
Answer	No

Document Name	
Comment	
The SRC supports the position that the Balancing Authority is the correct responsible entity for assuring that its ACE performance is compliant with the current BAL performance requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 2,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	No
Document Name	
Comment	
Frequency Response (FR) is a function of both generating resources and load characteristics – both fall under the purview of the BA. A BA can set performance requirements for resources within its balancing authority area (BAA), which includes governor/inverter settings. Similar to reactive/voltage requirements, a GO/GOP must meet FR performance criteria set by the BA/TO/TOP. FR is maintained by BA coordination of all assets within the BAA. The proposal to modify the functional entity applicability for BAL-003-1.1 to add the GO/GOP does not give any additional assurance of FR related interconnection reliability as an individual resource may or may not have the ability to respond as intended for a specific frequency event; however, the proposed modification will significantly increase the operating, economic and administrative burdens on the GO/GOP. The perceived improvement in FR related reliability intended by broadening the applicability of the standard does not justify the added burdens that would be placed on all GO/GOPs.	
Likes 0	

Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted.	
Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	
For Chelan PUD, as a BAA that owns and operates all of the generation within the BAA, the current standard is sufficient.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
The SAR proposes to modify the standard to a single entity that has the "ability to" provide and control Frequency Response. We caution that an entity providing Frequency Response may not be the same entity that controls Frequency Response. We also believe some accountability should still exist with the Frequency Response Sharing Group or seclusive Balancing Authority to monitor Frequency Response sufficiency for their respective area.	

Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted.	
Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Tacoma Power believes that although Balancing Authorities do not inherently have frequency responsive capabilities, these capabilities can be acquired via contractual agreements and market products. FERC should consider providing direction as to who should be compensating BAs for acquiring frequency response products necessary to meet this standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The issues you raised are commercial issues that are outside the scope of the SAR drafting team.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed ISO-NE	
Answer	No
Document Name	
Comment	

NPCC believes that the Balancing Authority is the appropriate entity responsible for assuring that its ACE performance is compliant with the current BAL performance requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	
Comment	
Tri-State believes this revision is not necessary due to the obligations already existing in TOP-001-3. As required by TOP-001-3 Requirement R5, a Generator Operator must comply with each Operating Instruction issued by its Balancing Authority. This would already include providing frequency response when asked to. Therefore, Tri-State believes it is incorrect to state that there is no mechanism available to Balancing Authorities to compel generators to provide frequency response during an event.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted.	
Neil Swearingen - Salt River Project - 1,3,5,6 – WECC	
Answer	No

Document Name	
Comment	
SRP believes the responsibility is appropriately allocated to the Balancing Authority.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Casey Johnston - Concerned Electrical Engineer with 40 yrs in Electrical Industry - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
The majority of frequency response is provided by rotating masses, such as generators with synchronized torque and motors connected to the interconnection. There is compelling evidence and testimony from multiple sources—BAs, transmission operators, and NERC reports—to show that many synchronous generators, the primary source of primary frequency response, are not providing the expected proportional response to frequency excursions. This standard, BAL-003, should apply to NERC registered GO/GOPs as responsible entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted.	

Dori Quam - NorthWestern Energy - 1 – WECC	
Answer	Yes
Document Name	
Comment	
The majority of frequency response is provided by rotating masses, such as generators with synchronized torque and motors connected to the interconnection. There is compelling evidence and testimony from multiple sources—BAs, transmission operators, and NERC reports—to show that many synchronous generators, the primary source of primary frequency response, are not providing the expected proportional response to frequency excursions. Currently, there is no “mechanism” available to the BAs to compel Generator Owners or Generator Operators to have their facilities provide the necessary primary frequency response during an event. BAL-003 must be revised to address this shortcoming. This standard, BAL-003, should apply to NERC registered GO/GOPs as responsible entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted.	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
Puget Sound Energy (PSE) fully supports the SAR for Project 2017-01 and the proposed revisions. To address reliability, BAL-003-1.1 should be modified to impose requirements on individual generating facilities and not burden Balancing Authorities with the cost of procuring frequency response in the marketplace.	

Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted.	
Antonio Franco - Gridforce Energy Management, LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Gridforce Energy Management agrees and supports the SAR. Not all Balancing Authorities own an asset to contrubute with primary frequency response, which in the Western Interconnection is generally a synchronous generator governor.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted.	
James Ramos - Turlock Irrigation District - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	

Frequency response is mostly provided by motors and generators synchronized to the interconnection. There is compelling evidence and testimony from multiple sources—BAs, transmission operators, and NERC reports—to show that many synchronous generators, the primary source of primary frequency response, are not providing the expected proportional response to frequency excursions. Generator Owners (GOs) or Generator Operators (GOPs) should be required to have their facilities provide the necessary primary frequency response during an event. BAL-003 applicable to GOs and GOPs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted.	
Kevin Salsbury - Berkshire Hathaway - NV Energy – 5	
Answer	Yes
Document Name	
Comment	
The majority of frequency response is provided by generators, but yet, the current BAL-003-1.1 applicability section requires Balancing Authorities to comply with the standard. This standard does not provide any mechanism to compel Generator Owners or Generator Operators to provide the necessary primary frequency response during an event. In addition, the Balancing Authorities do not have authority to force the Generator Owners or Generator Operators to respond correctly in the case of an event.	
Likes 0	
Dislikes 0	
Response	

Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted.

Yvonne McMackin - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes
Document Name	2017-BAL003 SAR Unofficial_Comment_Form_NWPP_Nov2017_Grant PUD.docx
Comment	
Different types of generation and load have different abilities to provide frequency response, and the BA in which the generation or load is located is not necessarily the owner of the generation or load. The standard should recognize the fact that the BA may not be the owner and also allow for generators and load that do supply frequency response to be appropriately compensated for this service.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted.	

Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Austin Energy (AE) agrees with the revision to eliminate arbitrary allocation of responsibility. However, AE requests that Generator Owners and Generator Operators in the ERCOT Interconnection be exempted from this requirement. The Regional Standard, BAL-001-TRE-1 - Primary Frequency Response incorporates specific performance requirements for Generator Owners and Generator Operators related to setting Governor dead-band and droop parameters and providing Primary Frequency Response. In the ERCOT Interconnection, all generator	

governors (unless exempted by ERCOT) must be in service and performing with an un-muted response to ensure an Interconnection minimum Frequency Response to a frequency disturbance event.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted. To the extent that BAL-001-TRE-1 might already address this issue, the Standard Drafting Team will need to determine how the proposed requirement may conflict or coordinate with the regional standard.	
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 – WECC	
Answer	Yes
Document Name	
Comment	
The majority of frequency response is provided by rotating masses, such as generators with synchronized torque and motors connected to the interconnection. There is compelling evidence and testimony from multiple sources—BAs, transmission operators, and NERC reports—to show that many synchronous generators, the primary source of primary frequency response, are not providing the expected proportional response to frequency excursions. Currently, there is no "mechanism" available to the BAs to compel Generator Owners or Generator Operators to have their facilities provide the necessary primary frequency response during an event. BAL-003 must be revised to address this shortcoming.	
Likes 0	
Dislikes 0	
Response	

Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted.

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
SCL is both a BA and a GO/GOP. So this proposed revision will not change SCL's responsibility.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	

Sandra Shaffer - Berkshire Hathaway - PacifiCorp – 6	
Answer	Yes
Document Name	
Comment	
Frequency response is a measure of an interconnection's post-contingency response, and in WECC that comes primarily from generator governor action. Putting the obligation on the BA without also providing authority over the GOP to require frequency response creates a system where many entities do not have the means to meet compliance. Even if the allocation of obligation is corrected, it does not change the fact that the current metric of FRM does not accurately measure frequency response. It can be clearly shown that change in BAA net interchange does not accurately measure the frequency response supplied by that BAA if it is in a finite interconnection. By using interchange as a proxy for frequency response in a finite interconnection, we are left with a zero-sum game where BAs compete for a share of the contingent unit credit. This has created a situation where in order to meet compliance, it can be beneficial to reduce system reliability by	

delaying/gaming governor settings. Alternatively, it is possible for a BA to unilaterally over-respond and cause other entities to fail where their only recourse for compliance is to purchase FRM from that entity or shed load.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted. The revised SAR will also allow for the other issues raised in your response to be reviewed by the Standard Drafting Team.	
Mike Magruder - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
The majority of frequency response is provided by rotating masses, such as generators with synchronized torque and motors connected to the interconnection. There is compelling evidence and testimony from multiple sources—BAs, transmission operators, and NERC reports—to show that many synchronous generators, the primary source of primary frequency response, are not providing the expected proportional response to frequency excursions. Currently, there is no “mechanism” available to the BAs to compel Generator Owners or Generator Operators to have their facilities provide the necessary primary frequency response during an event. There may be other resources available to provide primary frequency response, but there is also no “mechanism” available to compel these operating entities configure their facilities to provide primary frequency response. BAL-003 must be revised to address this shortcoming.	
Likes 0	
Dislikes 0	
Response	

Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted.	
Angela Gaines - Portland General Electric Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
BAL-003 should be revised to include some sort of mechanism for BAs to compel GOs and GOPs to provide the necessary primary frequency response during events. Currently there is no such mechanism, despite the fact that there is strong evidence that many synchronous generators, whose rotating masses provide the majority of frequency response, are not providing a proportional response to frequency events.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted.	
David Ramkalawan - Ontario Power Generation Inc. – 5	
Answer	Yes
Document Name	
Comment	
OPG agrees with closing the reliability gap with respect to the applicable entity as long as the requirements to the GO/GOP are properly and clearly defined.	

OPG support the clarification of non-synchronous generation compliance obligation for the provision of essential reliability services like frequency control and ramping capability/flexible capacity. We are also in agreement with the revision of the allocation formula to adequately reflect the composition of the grid and more accurately place the burden of frequency response.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted. In addition, the SAR will allow the Standard Drafting Team to review the allocation methodology.	
Rachel Coyne - Texas Reliability Entity, Inc. – 10	
Answer	Yes
Document Name	
Comment	
Texas RE appreciates the SDT's efforts to properly align compliance responsibilities for providing frequency response with those Registered Entities actually capable of performing that specific reliability task. To that end, Texas RE agrees that the BAL-003 Standard should impose certain mandatory frequency response requirements on Generation Owners (GO) and Generation Operators (GOP). As the accompanying technical guidance document sets forth, the current BAL-001-TRE-1 Standard requires GOs and GOPs to set governor droop and deadband settings in accordance with specified criteria (BAL-001-TRE-1 R6), operate with their governor in service (BAL-001-TRE-1 R7), and meet both initial and sustained frequency response performance metrics (BA-001-TRE-1 R9 and R10). Texas RE recommends that the SDT consider these collective approaches in designing a new BAL-003 Standard.	
Likes 0	
Dislikes 0	

Response	
Thank you for your response and reference to Texas RE documents.	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
The majority of frequency response is provided by rotating masses, such as generators with synchronized torque and motors connected to the interconnection. There is compelling evidence and testimony from multiple sources—BAs, transmission operators, and NERC reports—to show that many synchronous generators, the primary source of primary frequency response, are not providing the expected proportional response to frequency excursions. Currently, there is no “mechanism” available to the BAs to compel Generator Owners or Generator Operators to have their facilities provide the necessary primary frequency response during an event. BAL-003 must be revised to address this shortcoming. For small BAs with a limited amount of generation and tie lines Net Interchange does not provide a precise measure of actual response when the required response for a BA is less than 1 MW/0.1Hz during a disturbance. Tie line meters toggling a single whole MW in the incorrect direction could make it appear that the BA responded in the wrong direction when generation does show a response in the correct direction.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted. The Standard Drafting Team will review the measurement methodology.	
Jeff Rehfeld - NaturEner USA, LLC - 5 – WECC	
Answer	Yes

Document Name	
Comment	

Comments: The majority of frequency response is provided by rotating masses, such as generators with synchronized torque and motors connected to the interconnection. There is compelling evidence and testimony from multiple sources—BAs, transmission operators, and NERC reports—to show that many synchronous generators, the primary source of primary frequency response, are not providing the expected proportional response to frequency excursions. Currently, there is no "mechanism" available to the BAs to compel Generator Owners or Generator Operators to have their facilities provide the necessary primary frequency response during an event. BAL-003 must be revised to address this shortcoming, subject to the considerations set forth in the immediately following paragraph.

A one-size fits all blanket rule should not be imposed which requires all generators to have to install capability to provide primary frequency response above their inherent characteristics/capabilities. Among other things, mandating that all generators be required to install capabilities to provide primary frequency response (1) fails to take into account the individual characteristics of different generator types and their unique advantages and disadvantages (e.g., wind generators' limited ability and cost-prohibitive impact of providing primary frequency response in an under-frequency event situation) as well as diversity benefits, (2) is uneconomical and will result in an inefficient use of limited resources (the costs may often dwarf any limited benefit), (3) may result in an oversupply of frequency response, (4) will hinder if not effectively "crowd out" the development of more efficient approaches including options for compliance offered (or at least complemented) by frequency response sharing groups/pools, bilateral contracts and other always emerging market solutions, and (4) may decrease the ability to provide secondary frequency response.

Likes 0	
Dislikes 0	

Response

Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted. Finally, a requirement that focuses only on the GO/GOP could cause questions related to other entities being allowed to provide resources that can provide the response.

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3

Answer	Yes
Document Name	
Comment	
Adding the frequency response obligation to the BA without also providing authority over the GOP to require frequency response creates a system where some entities may not have the means to meet compliance. Using interchange as a proxy for frequency response may be inaccurate and needs further review.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted. The Standard Drafting team will review the measurement methodologies.	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF, Group Name Consumers Energy Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Mike Smith - Manitoba Hydro - 1,3,5,6, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your affirmative response.	
John Tolo - Unisource - Tucson Electric Power Co. – 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 – WECC	
Answer	
Document Name	
Comment	
BPA is a member of the WFRSG and supports the WFRSG SAR. There are many things in the current BAL-003 standard that need to be changed.	

BPA assumes this question relates to adding the GO/GOP to the list of applicable entities for this standard. BPA disagrees that the GO/GOP should be added to the list of responsible entities. BPA believes that the BA is the responsible entity for this standard. Frequency Response should be considered another product procured from a generator or load by the BA to meet its responsibilities the same as Schedules 3, 5 and 6. The BA has the wide area view needed for determining the amount of frequency responsive reserve that should be held to meet its compliance obligation. BPA is concerned that a GO/GOP requirement could lead to inefficient operations of a generation fleet, because too much capacity would be held aside for frequency response. Through participation in the WFRSG BPA has heard the concerns of many BA's related to the current BAL-003 standard and respects their position regarding their inability to require a generator to provide frequency response. BPA believes that the Standard Drafting Team should hear arguments and fully evaluate the standard to determine the correct applicable entity or entities. In addition, BPA takes issue in how this question is presented. BPA did not see a specific proposed revision in the above question, and therefore finds it hard to answer either yes or no. Instead BPA was forced to make its own assumptions regarding what the question pertained to. Therefore we cannot provide specific language, because no specific revision was proposed. In general, BPA does support the drafting team considering a revision to the standard to reflect what is required for real-time reliability.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted.	

2. The SAR proposes to modify the current BAL-003-1.1 standard to allow for real-time measurement of frequency performance instead of a two year old allocation. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6	
Answer	No
Document Name	
Comment	
AECI has concerns with the proposed modifications that allow for real-time frequency performance instead of a two year old allocation. Sufficient detail has not been presented in regards to this approach. Would a Responsible Entity be required to meet frequency response obligations for every event? Would there be any exemptions for a Responsible Entity that is experiencing the generation loss? AECI sees merit in the approach, but cannot agree with the proposal in question 2 until further details are provided.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	
Neil Swearingen - Salt River Project - 1,3,5,6 – WECC	
Answer	No
Document Name	
Comment	
Without a clear proposed method of Real-Time measurement, SRP cannot support the implementation of such a change. Neither can SRP provide specific language revisions. SRP is concerned the proposed transition to Real-Time measurement could incur high costs from overly	

strict operating conditions or other unforeseen consequences. Moreover, the current measure, though retrospective, is effective in creating sufficient frequency response in each interconnection.	
Likes 0	
Dislikes 0	
Response	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	
Answer	No
Document Name	
Comment	
Linking real time frequency to real time asset response may be inappropriate since generation production may not be not a continuous function of each asset. NPCC supports the current concept that the diversity of primary response is properly reflected in the use of long-term average frequency for computing the bias settings utilized in the ACE equation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	
Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	No
Document Name	
Comment	

Tacoma Power does not believe real time monitoring should be prescribed through reliability standards. However, Tacoma believes that behind the meter solar has become prevalent enough so that it requires both the generator and load, which are behind the meter, be included in the BAs portion of the Interconnection Frequency Reserve Obligation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	No
Document Name	
Comment	
Xcel Energy has concerns on how this would be implemented. It is important to be able to look at the data from each event to verify accuracy and make adjustments. Synchronized real time data would be optimal and may be required. Further, if generator owners will be required to operate with governors in-service with defined droop and deadband, allowances must be made for generator owners to notify transmission coordinators if a failure occurs that prevents equipment from operating in its normal manner and prevents frequency response. The AGC frequency bias logic is used so AGC signal does not wash out primary frequency response of turbine-generators. This can also be applied for other equipment failure modes.	
Likes 0	
Dislikes 0	
Response	

Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted. The revised SAR also provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.

Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Chelan PUD

Answer	No
Document Name	

Comment

While the allocation may use two-year-old data, Chelan PUD believes the standard is sufficient for its intended purpose.

Likes 0	
Dislikes 0	

Response

Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.

Shelby Wade - PPL - Louisville Gas and Electric Co. - 2,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company

Answer	No
Document Name	

Comment

Concern over Frequency Response (FR) to large, infrequent loss of resource events that significantly impact interconnection frequency has taken years to develop and rose to a level justifying the creation of a reliability standard (BAL-003-1.1). The standard is relatively new and has been effective in raising awareness of FR and assigning responsibility for FR performance. Unless there is evidence that the standard is not stabilizing/improving an interconnection's FR, it seems premature to take the significant step of making FR a real-time reliability issue.

Making FR a real-time issue would have significant operating, economic and administrative impacts. The provision, monitoring and reporting of FR Resources (FRR) would be analogous to Operating Reserves (Contingency and Regulating Reserves). Such an effort does not seem justified unless the inadequacy of the current BAL-003-1.1 can be clearly demonstrated and there is a lack in reliability. If a new way of calculating FR is proposed utilizing real-time information, then NERC should consider a voluntary field trial using the new methodology (similar to BAAL). This would allow companies to assess their historical FR calculation and compare it to the FR calculated under a new methodology.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies; justification would accompany any modifications.	
Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - SERC,RF, Group Name ISO Standards Review Committee	
Answer	No
Document Name	
Comment	
The concept of linking real time frequency to real time asset response ignores the fact that generation production is not a continuous function for each asset. The SRC supports the current concept that the diversity of primary response is properly reflected in the use of long-term average frequency for computing the bias settings utilized in the ACE equation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	No
Document Name	
Comment	
PJM sees merit in real-time measurement in frequency response reserves and performance. However, PJM does not see this as a replacement for the historical performance assessments and allocations of frequency bias.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	
Leonard Kula - Independent Electricity System Operator – 2	
Answer	No
Document Name	
Comment	
Linking real time frequency to real time asset response may be inappropriate since generation production may not be not a continuous function of each asset. The IESO supports the current concept that the diversity of primary response is properly reflected in the use of long-term average frequency for computing the bias settings utilized in the ACE equation.	
Likes 0	
Dislikes 0	
Response	

Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies; justification would accompany any modifications.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
The scope and complexity of the work defined in the SAR indicates a large effort which if incorporated with Phase I will delay making the needed corrections. The phased approach needs to be two distinctive processes. We should not delay the correction proposed in phase I to incorporate any proposed modifications that are noted in phase II. This SAR needs to address only the changes required after modifications of Phase I are complete.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will include a phased approach echoing your comments.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
It is unclear whether the real-time measurement would wholly replace the current method for calculation and allocation or is being proposed to provide additional benefits in real-time. Without clarity regarding the proposal and its potential for impacts, AZPS is concerned that the SAR is not clear enough to allow for proper evaluation. If the intent is to wholly replace the current methods of calculation and allocation, AZPS cannot support such proposal as such would significantly increase costs and complicate resource planning and adequacy efforts. No evidence	

has been offered as to reliability issues occurring due to neither the current method nor how a real-time measurement would resolve those issues.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
Although City Light agrees with the issues identified with the current standard (such as the assumption that frequency response is linear; using last two-year information to allocate IFRO; and performance is determined by the median event of historical responses,) City Light still thinks the existing standard is sufficient for the intended use at this time. To do the calculations for the real-time measurement of frequency performance for all kinds of real time system conditions and next N-1 contingencies will be very difficult to implement and probably will not be cost effective.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No

Document Name	
Comment	
Real-time measurement of frequency performance has merit, but it should be in addition to, not a substitute for, determination of frequency bias settings. Much like DCS requirements, there is merit in requirements for both performance and longer term determination of minimum response requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	
Thomas Foltz - AEP - 3,5	
Answer	No
Document Name	
Comment	
AEP believes that a Real-time assessment of frequency performance, or an after-the-fact assessment of frequency performance such as required in BAL-001-TRE, is neither possible nor advisable for an interconnection having excess synchronous inertia that limits the extent of n-1 frequency events. The “two year old allocation” of the existing standard is sufficient for the intended use at this time.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
Allowing for a real-time measurement of frequency performance appears to be an improvement.	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Jeff Rehfeld - NaturEner USA, LLC - 5 – WECC	
Answer	Yes
Document Name	
Comment	
Comments: Frequency response is required and provided during real-time resource contingencies within the interconnection. Currently BAL-003-1.1 does not measure at the time of the event the ability to provide frequency response nor does it identify the parties that may have the ability to respond under the current real-time topology (transmission, generation and demand). Utilizing two year old data to allocate the Interconnection Frequency Response Obligation fails to recognize real-time conditions and how topologies may change.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	

sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Frequency response is required and provided immediately after an event occurs within the interconnection. Currently BAL-003-1.1 provides no mechanism to ensure the availability to provide frequency response at the time of the event nor does it reflect current real-time topology that may limit the ability to respond (transmission, generation and demand). The use of historical data to determine the median response for BAL-003 compliance reporting provides no assurance that all BAs will respond realtime to all disturbances. If a Balancing Authority has a known shortage during a certain time of year the BA could chose to not provide the required response for that period and rely on the rest of the events in the compliance period to pass the standard given the current measurement criteria. Utilizing two year old data to allocate the Interconnection Frequency Response Obligation fails to recognize real-time conditions and how topologies may change.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG agrees with the real-time measurement of frequency performance and expresses concerns with respect to the extent of the implications for all involved existing ICCP communication/control links that do not satisfy the latency requirements.	
Likes 0	

Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	
Angela Gaines - Portland General Electric Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
The current standard's use of two-year old data does not take into account real-time conditions and the changing nature of topologies and therefore does not provide an adequate way of measuring frequency performance. The standard should be revised to address the ability of a party to provide real-time frequency response during resource contingencies.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	
Mike Magruder - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Frequency response is required and provided during real-time resource contingencies within the interconnection. Currently BAL-003-1.1 does not measure at the time of the event the ability to provide frequency response nor does it identify the parties that may have the ability to	

respond under the current real-time topology (transmission, generation and demand). Utilizing two year old data to allocate the Interconnection Frequency Response Obligation fails to recognize real-time conditions and how topologies may change.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Load and generation profiles are rapidly changing, and using old data from Form 714 to allocate a static obligation is grossly inaccurate. Once again, the standard incorrectly assumes that every BA is identical when there exist vast differences in load profiles and resource mix. Allocation would have to be real-time and dynamic in order to be accurate. In WECC, BAA's are currently required to calculate 3% of their real time load and generation, and this value is used as a requirement for Contingency Reserves. Additionally a real time calculation of estimated available capacity is also required. A similar real time calculation should be feasible and could more accurately represent system conditions in real time for the purposes of frequency response requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	

Answer	Yes
Document Name	
Comment	
Frequency response is required and provided during real-time resource contingencies within the interconnection. Currently BAL-003-1.1 does not measure at the time of the event the ability to provide frequency response nor does it identify the parties that may have the ability to respond under the current real-time topology (transmission, generation and demand). Utilizing two year old data to allocate the Interconnection Frequency Response Obligation fails to recognize real-time conditions and how topologies may change.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
AE agrees with the modification to allow for real-time measurement of frequency events to assess primary frequency performance. However, AE requests the ERCOT Interconnection be exempted from this requirement. The Regional Standard, BAL-001-TRE-1 - Primary Frequency Response incorporates specific requirements for the Balancing Authority related to identifying actual real-time Frequency Measureable Events, calculating the Primary Frequency Response of each generation resource in the Region, calculating the Interconnection minimum Frequency Response and monitoring the actual Frequency Response of the Interconnection.	
Likes 0	
Dislikes 0	

Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies. To the extent that BAL-001-TRE-1 might already address this issue, the Standard Drafting Team will need to determine how the proposed requirement may conflict or coordinate with the regional standard.	
Yvonne McMackin - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes
Document Name	
Comment	
BAs can have large changes in their generation mix from year to year. A large generator could be removed from a BA either by shutting down of being placed in another BA while continuing to operate. In this case, the FRO for the BA in a particular year could be artificially high for one BA and artificially low for another due to the delay involved to determine the FRO. If a frequency standard examined generator response rather than a measure related to a BA, this inequity should not occur.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	
Kevin Salsbury - Berkshire Hathaway - NV Energy – 5	
Answer	Yes
Document Name	
Comment	
The current BAL-003-1.1 standard has the Balancing Authority reviewing and analyzing event data that was taken over a year ago to see if the Balancing Authority met the minimum requirement. After reviewing and analyzing the events, if the Balancing Authority discovers it did not	

meet the standard, it is too late for the Balancing Authority to try and resolve the issue. If the Balancing Authority had the chance to correct the issue, this would increase reliability of the grid and give the Balancing Authority another chance to pass the standard. The current purpose of the BAL-003-1.1 standard is to maintain Interconnection Frequency by arresting frequency deviations, and this can only be done if the standard requires real time analysis. Real time analysis and requirements would allow all parties to review and adjust how their units will respond to the next event.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	
James Ramos - Turlock Irrigation District - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Although frequency response is required and actually provided in real-time to address resource contingencies within the interconnection, the current BAL-003-1.1 does not measure at the time of the event the ability to provide frequency response nor does it identify the parties that may have the ability to respond under the current real-time topology (transmission, generation and demand). Utilizing two year old data to allocate the Interconnection Frequency Response Obligation fails to recognize real-time conditions and how topologies may change.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	

Antonio Franco - Gridforce Energy Management, LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Griforce Energy Management agrees and supports the SAR. The allocation of FRO should happen real time based on system conditions and available resources to support potential losses of resource output. Therefore, BA's actual FRO should be a dynamic target based on the BA's real time generation plus load during a BAL-003 event selected by the NERC FWG.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
Puget Sound Energy (PSE) fully supports the SAR for Project 2017-01 and proposed revisions. FERC Form 714 does not accurately show the state of the interconnection because it uses historical data that is over 2-years old; data should be current or at least within the last (rolling) 12 month period.	
Likes 0	
Dislikes 0	
Response	

Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	
Dori Quam - NorthWestern Energy - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Frequency response is required and provided during real-time resource contingencies within the interconnection. Currently BAL-003-1.1 does not measure at the time of the event the ability to provide frequency response nor does it identify the parties that may have the ability to respond under the current real-time topology (transmission, generation and demand). Utilizing two-year-old data to allocate the Interconnection Frequency Response Obligation fails to recognize real-time conditions and how topologies may change. The SAR to modify BAL-003-1.1 should specify criteria and design calculations for the real-time measurement of frequency performance.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	
Casey Johnston - Concerned Electrical Engineer with 40 yrs in Electrical Industry - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Frequency response is required and provided during real-time resource contingencies within the interconnection. Currently BAL-003-1.1 does not measure at the time of the event the ability to provide frequency response nor does it identify the parties that may have the ability to respond under the current real-time topology (transmission, generation and demand). Utilizing two year old data to allocate the	

Interconnection Frequency Response Obligation fails to recognize real-time conditions and how topologies may change. The SAR to modify BAL-003-1.1 should specify criteria and design calculations for the real-time measurement of frequency performance.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your affirmative response.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Mike Smith - Manitoba Hydro - 1,3,5,6, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your affirmative response.	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF, Group Name Consumers Energy Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	

BPA is a member of the WFRSG and supports the WFRSG SAR. There are many things in the current BAL-003 standard that need to be changed.

BPA does not know how to interpret this question. Mention of the real time measure of frequency performance does not seem to fit with the allocation of the IFRO. BPA does see issues in the two year old data used to allocate responsibility. BPA encourages the Standards Drafting Team to consider revising how the IFRO is allocated.

BPA takes issue in how this question is presented. BPA did not see a specific proposed revision in the above question, and therefore finds it hard to answer either yes or no. Instead BPA was forced to make its own assumptions regarding what the question pertained to. Therefore we cannot provide specific language, because no specific revision was proposed. In general, BPA does support the drafting team considering a revision to the standard to reflect what is required for real-time reliability.

Likes 0	
Dislikes 0	

Response
Thank you for your response. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.

3. The SAR proposes to modify the current BAL-003-1.1 standard to eliminate the incorrect signals to the market for arbitrary pricing and conditions. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

Thomas Foltz - AEP - 3,5

Answer	No
Document Name	

Comment

AEP believes that a Reliability Standard is adopted to sustain or improve reliability, and not to support the energy markets. Discussion of commercial considerations is outside the scope of a Reliability Standard and should not be matters of discussion within standards development.

Likes 0	
Dislikes 0	

Response

The SAR drafting team appreciates your comment and agrees with your response that the commercial and market design considerations are outside the scope of reliability standard. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 – SERC

Answer	No
Document Name	

Comment

This is a Balancing Authority control issue and should not be applied to a NERC Standard. Should not this be addressed in BAL-001?

Likes 0	

Dislikes 0	
Response	
Thank you for your response. The Standard Drafting Team will review and recommend requirements that may affect other Reliability Standards.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
The information in the SAR and the background document do not provide enough information to clearly understand the intent of the perceived problem or a proposed solution to it.	
Likes 0	
Dislikes 0	
Response	
The SAR drafting team appreciates your comment. The SAR drafting team has combined the two SARs (NERC RS and NW FRSG) and attempted to provide additional clarity of the perceived issues.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	
This is a reliability standard. It is not appropriate to discuss the Market Pricing here.	
Likes 0	
Dislikes 0	

Response	
Thank you for your response.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
AZPS respectfully asserts that market issues and/or distortions are not appropriate justifications for the revision of reliability standards. While a reliability standard should not interfere with market principles, they are not the appropriate vehicle to “cure” market issues. Such issues are often market-specific and, therefore, are better addressed within the stakeholder processes of the Market Operator or with the FERC. Additionally, AZPS notes that the SAR is unclear about the specific market distortions being caused by BAL-003-1, its intent or method for correction, and how the proposed revisions would correct the identified distortions. AZPS has not observed any market-related distortions as a result of BAL-003-1 and, without adequate and sufficient information and justification, cannot support revision.	
Likes 0	
Dislikes 0	
Response	
The SAR drafting team appreciates your comment and agrees with your response that the commercial and market design considerations are outside the scope of reliability standard. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
The SAR does not provide details of the incorrect market signals to determine if this is needed or required.	

Likes 0	
Dislikes 0	
Response	
The SAR drafting team appreciates your comment. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
The IESO does not agree with linking NERC standards to market mechanisms/decisions. NERC standards should be written only to meet reliability objectives.	
Likes 0	
Dislikes 0	
Response	
The SAR drafting team appreciates your comment. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	No
Document Name	
Comment	
PJM does not believe it is appropriate for NERC to address market signals or pricing.	
Likes 0	

Dislikes 0	
Response	
The SAR drafting team appreciates your comment. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.	
Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - SERC,RF, Group Name ISO Standards Review Committee	
Answer	No
Document Name	
Comment	
The SRC does not agree that this NERC standard is or should be linked to Market decisions.	
Likes 0	
Dislikes 0	
Response	
The SAR drafting team appreciates your comment. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.	
Rachel Coyne - Texas Reliability Entity, Inc. – 10	
Answer	No
Document Name	
Comment	
Texas RE supports eliminating arbitrary estimates and non-comparable formulas where appropriate. The SDT will need to clearly demonstrate the specific aspects of the current Standard that result in incorrect signals to provide primary frequency response, as well as other unintended consequences stemming from the current Standard design. Texas RE looks forward to reviewing and carefully considering this specific evidence in the Standard Development process.	

Likes 0	
Dislikes 0	
Response	
The SAR drafting team appreciates your comment. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 2,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	No
Document Name	
Comment	
While the SAR appears to propose some kind of modifications on market signals, there is insufficient information in the SAR and no information at all in the supporting materials to understand what is being proposed to be addressed or modified. In any case, the market signal issue should only be addressed in a SAR if it is directly connected to reliability. Reliability standards should address reliability issues; they are not the appropriate vehicle for addressing market issues.	
Likes 0	
Dislikes 0	
Response	
The SAR drafting team appreciates your comment and agrees with your response that the commercial and market design considerations are outside the scope of reliability standard. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.	
Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Chelan PUD	
Answer	No
Document Name	
Comment	

Standards exist and should be written to improve reliability and not to evaluate commercial considerations. The Standard drafting team should simply ensure that what is written can achieve a reliability benefit in excess of the costs needed to achieve that benefit.

Likes 0	
Dislikes 0	

Response

The SAR drafting team appreciates your comment. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer	No
Document Name	

Comment

It's not clear how this can be accomplished nor why a market rule should not be developed instead of altering a reliability requirement.

We encourage the drafting team to consider the previous NERC Advisory on Generator Frequency Response of 2015 and the Reliability Guideline on Primary Frequency Control. If generator owners will be required to operate with defined droop and deadband, guidance on correct droop and deadband for each type of plant would be appreciated. The 2015 Advisory did not differentiate between fossil, nuclear, combined cycle, etc; there was, however, some guidance in the Reliability Guideline. We also request the drafting team to consider the limitations of nuclear units to provide frequency response to under-frequency events.

Likes 0	
Dislikes 0	

Response

Thank you for your response. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.

The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The Standard Drafting Team will address the issue of supporting any additional requirements during the drafting process if it is determined that such additions are warranted.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We caution the reference to arbitrary market pricing and elimination of market signals in the reliability standard development process. NERC Reliability Standards focus on developing a results-based approach regarding the performance and capabilities of registered entities and their operations, planning, and risk management activities regarding the bulk power system. We disagree that it is NERC regulations that drive market signals, and we believe such references should be removed from the SAR.	
Likes 0	
Dislikes 0	
Response	
The SAR drafting team appreciates your comment and agrees with your response that the commercial and market design considerations are outside the scope of reliability standard. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.	
Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Tacoma Power believes that although Balancing Authorities do not inherently have frequency responsive capabilities, these capabilities can be acquired via contractual agreements and market products. It appears the current market is not arbitrary. FERC should consider providing direction as to who should be compensating BAs for acquiring frequency response products necessary to meet this standard. However,	

Tacoma suggests that NERC review the standard for alignment between desired frequency performance and existing performance measurement.	
Likes 0	
Dislikes 0	
Response	
The SAR drafting team appreciates your comment and agrees with your response that the commercial and market design considerations are outside the scope of reliability standard. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed ISO-NE	
Answer	No
Document Name	
Comment	
NPCC does not agree with linking NERC standards to market mechanisms/decisions. NERC standards should be written only to meet reliability objectives.	
Likes 0	
Dislikes 0	
Response	
The SAR drafting team appreciates your comment and agrees with your response that the commercial and market design considerations are outside the scope of reliability standard. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	

Answer	No
Document Name	
Comment	
SRP supports the comments submitted by AZPS in response to question 3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response provided to AZPS.	
Casey Johnston - Concerned Electrical Engineer with 40 yrs in Electrical Industry - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
BAL-003 should not create a new market for a reliability product that currently exists. Under the current version of BAL-003-1.1 a GO/GOP can charge customers twice for the same capacity needed for reliability purposes. The difference between the capacity products is simply a time measurement period. For example, 10 MW of Contingency Spinning Reserves can also be sold as FRR. This is the same product and capacity but the customer pays twice.	
Likes 0	
Dislikes 0	
Response	
The SAR drafting team appreciates your comment and agrees with your response that the commercial and market design considerations are outside the scope of reliability standard. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.	

Dori Quam - NorthWestern Energy - 1 – WECC	
Answer	Yes
Document Name	
Comment	
BAL-003 should not create a new market for a reliability product that currently exists. Under the current version of BAL-003-1.1 a GO/GOP can charge customers twice for the same capacity needed for reliability purposes. The difference between the capacity products is simply a time measurement period. For example, 10 MW of Contingency Spinning Reserves can also be sold as FRR. This is the same product and capacity, but the customer pays twice.	
Likes 0	
Dislikes 0	
Response	
The SAR drafting team appreciates your comment and agrees with your response that the commercial and market design considerations are outside the scope of reliability standard. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
The current standard is overly burdensome on Balancing Authorities with compliance obligations to maintain reliability because it provides no recourse if a Generator Owner (GO) does not implement and provide frequency response capabilities. GOs are an inherent part of the Bulk Electric System and are the best resource to support immediate frequency response needs on the Interconnection.	
Likes 0	
Dislikes 0	

Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies; justification would accompany any modifications.	
James Ramos - Turlock Irrigation District - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
BAL-003 should drive market signals that reflect what is truly needed for reliability, to ensure 100% coverage for the interconnection through equipment capability, capacity, and dispatch, and provide correct signals to the parties with the ability to deliver real-time frequency response.	
Likes 0	
Dislikes 0	
Response	
The SAR drafting team appreciates your comment and agrees with your response that the commercial and market design considerations are outside the scope of reliability standard. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.	
Kevin Salsbury - Berkshire Hathaway - NV Energy – 5	
Answer	Yes
Document Name	
Comment	

BAL-003-1.1 should drive market signals that reflect what is truly needed for reliability, to ensure 100% coverage for the interconnection through equipment capability, capacity, dispatch, and provide correct signals to the parties with the ability to deliver real-time frequency response. The conditions that have been set in the standard are arbitrary, especially in regards to when, how, and where you need them.	
Likes 0	
Dislikes 0	
Response	
The SAR drafting team appreciates your comment and agrees with your response that the commercial and market design considerations are outside the scope of reliability standard. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.	
Yvonne McMackin - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes
Document Name	
Comment	
Grant PUD would like to stress there is **nothing arbitrary** about the pricing that has occurred for the supply of frequency response. When Grant PUD has determined prices to use in responding to RFPs for frequency response, we have carefully considered the risks involved and the finite supply available. The fact that RFPs are generally used by a purchaser indicates pricing is not arbitrary.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 – WECC	
Answer	Yes

Document Name	
Comment	
BAL-003 should drive market signals that reflect what is truly needed for reliability, to ensure 100% coverage for the interconnection through equipment capability, capacity, and dispatch, and provide correct signals to the parties with the ability to deliver real-time frequency response.	
Likes 0	
Dislikes 0	
Response	
The SAR drafting team appreciates your comment and agrees with your response that the commercial and market design considerations are outside the scope of reliability standard. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp – 6	
Answer	Yes
Document Name	
Comment	
While PacifiCorp does not believe the pricing of FRM in and of itself has been arbitrary, it is clear that the calculation and allocation of FRM is inaccurate and arbitrary, and therefore has created an arbitrary product for which BAA's have had to create prices, buy and sell. Therefore PacifiCorp strongly agrees that the mechanisms behind these calculations and allocations need to be addressed.	
Likes 0	
Dislikes 0	
Response	

Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies; justification would accompany any modifications.	
Mike Magruder - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
A Reliability Standard does not address market issues, but at the same time, a Reliability Standard should establish a performance requirement that supports system reliability. "Meeting the requirement" should enhance reliability, which is the goal of the standard. R1 measures the median performance of a BA over a 12 month period. Every BA in the interconnection could fail to provide FRR for a single event, the interconnection could suffer underfrequency load shedding and eventual break up, and each BA would still pass R1 if it met the median requirement for the measurement year. It seems that BAL-003-1 does not enhance system reliability, but could encourage operational practices that could degrade system reliability. If a BA has passed 13 events (assuming 25 for the year), after the 13th pass, the BA could alter its generation operations minimizing primary frequency response, still passing for the year, but degrading overall reliability for a portion of the year.	
Likes 0	
Dislikes 0	
Response	
The SAR drafting team appreciates your comment and agrees with your response that the commercial and market design considerations are outside the scope of reliability standard. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.	
Angela Gaines - Portland General Electric Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

BAL-003 should provide correct market signals to those parties who are able to deliver real-time frequency response and that reflect what is actually needed to ensure complete coverage for the Interconnection through equipment capability, capacity and dispatch.	
Likes 0	
Dislikes 0	
Response	
The SAR drafting team appreciates your comment and agrees with your response that the commercial and market design considerations are outside the scope of reliability standard. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
BAL-003 should drive market signals that reflect what is truly needed for reliability, to ensure 100% coverage for the interconnection through equipment capability, capacity, and dispatch, and provide correct signals to the parties with the ability to deliver real-time frequency response. Purchase and Sale of Frequency Response does nothing to maintain or improve the Frequency Response of the bulk system, instead it drives a market to equitably distribute the actual historical Frequency Response between all entities in an interconnection.	
Likes 0	
Dislikes 0	
Response	
The SAR drafting team appreciates your comment and agrees with your response that the commercial and market design considerations are outside the scope of reliability standard. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	

Answer	Yes
Document Name	
Comment	
The SPP Standards Review Group has a concern that the proposed modification could create Marketing issues outside the scope of the Standards Drafting Team.	
Likes 0	
Dislikes 0	
Response	
The SAR drafting team appreciates your comment. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.	
Jeff Rehfeld - NaturEner USA, LLC - 5 - WECC	
Answer	Yes
Document Name	
Comment	
Comments: BAL-003 should drive market signals that reflect what is truly needed for reliability, to ensure 100% coverage for the interconnection through equipment capability, capacity, and dispatch, and provide correct signals to the parties with the ability to deliver real-time frequency response, each subject to and mindful of the considerations raised by Commenter in the second paragraph to its Comments to Question 1 above.	
Likes 0	
Dislikes 0	
Response	

The SAR drafting team appreciates your comment and agrees with your response that the commercial and market design considerations are outside the scope of reliability standard. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
If using interchange as a proxy for frequency response contains inaccurate signals then system reliability could be negatively impacted. Mandatory NERC standards that carry penalties must be accurate and cannot negatively impact system reliability.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address additional reliability entities. The revised SAR provides recommendations to the Standard Drafting Team, including the review of measurement and allocation methodologies; justification would accompany any modifications.	
Antonio Franco - Gridforce Energy Management, LLC - NA - Not Applicable – WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your affirmative response.	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF, Group Name Consumers Energy Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Mike Smith - Manitoba Hydro - 1,3,5,6, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	

John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response.	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
BPA is a member of the WFRSG and supports the WFRSG SAR. There are many things in the current BAL-003 standard that need to be changed. A market has been created due to this standard; however, BPA sees no market signals in the standard. BPA is not sure what is meant by arbitrary prices. On the subject of markets, BPA does have concerns looking into the future, with the median FRM being used for compliance and driving a market based on median performance. BPA takes issue in how this question is presented. BPA did not see a specific proposed revision in the above question, and therefore finds it hard to answer either yes or no. Instead BPA was forced to make its own assumptions regarding what the question pertained to. Therefore we cannot provide specific language, because no specific revision was proposed. In general, BPA does support the drafting team considering a revision to the standard to reflect what is required for real-time reliability.	
Likes 0	

Dislikes 0	
Response	
The SAR drafting team appreciates your comment. Although the revised SAR does address potential reliability issues, it does not address purely commercial issues.	

4. Based on the scope of the Phase II section of the SAR, do you have any other comments for drafting team consideration?	
Mark Riley - Associated Electric Cooperative, Inc. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 – WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Tolo - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1,3,5,6, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF, Group Name Consumers Energy Company	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion NextERA Con-Ed ISO-NE	
Answer	Yes
Document Name	
Comment	

NPCC supports the original SAR (proposed by the NERC RS and posted in June/July of this year) to correct inappropriate assumptions in the current standard. If this SAR is intended to replace or supplement the original SAR, then the following process issues arise:

- There lacks clarity as to what may happen to the first SAR. If the intent is to proceed with the first phase per the first SAR, then this currently posted SAR should be submitted as an addendum to the first SAR. It is confusing, and inappropriate, to post 2 SARs addressing in whole or in part of the same proposed project.
- Posting this SAR for industry comment may be premature, given that the first phase hasn't yet been completed and hence changes to the existing BAL-003 are not known. Some of the changes eventually embraced by the industry, adopted by the BOT and approved by regulatory authorities may address part or all of the reliability needs intended by the second phase.

The SAR lacks evidence of reliability needs/benefits to justify the second phase tasks.

Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed and allows a phased approach to addressing modifications to the existing standard.	
Jeff Rehfeld - NaturEner USA, LLC - 5 - WECC	
Answer	Yes
Document Name	
Comment	
Comments: The SAR identified several issues regarding the FRM as the sole measure of frequency response performance. The SAR stated: "The standard must be able to measure all types of Frequency Response and credit the providers. The current standard does not reflect different types of Frequency Response and the timing of such response." Please add the issue regarding the basis of measuring frequency response performance to this ballot.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether modification is necessary to revise the measurement and allocation methodology.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	

1. We reiterate from our previous comments that the scope identified within the SAR is too broad and appears to have no definite deadlines. The current proposal to split its activities into two separate phases is problematic, as the second phase is likely to result in a field trial. Will this delay the regulatory approval activities associated with the first phase? What happens if the first phase results in the issuance of FERC directives that will then need to be addressed in a third phase?
2. The previous SAR identified the possibility of relocating the standard's Attachment A to a NERC Operating Committee-approved reference document or Reliability Guideline. The proposed SAR does not clarify how this information will be treated in the future.
3. The SAR should be expanded to clarify frequency-related definitions listed within the NERC Glossary. For example, Frequency Response has two separate meanings in the NERC Glossary.
4. We thank you for this opportunity to provide these comments.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SAR drafting team has revised the SAR to identify issues to be addressed. The Revised SAR attempts to address issues to Attachment A and how they will be addressed going forward. The standard drafting team will address definitions as needed.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group

Answer	Yes
Document Name	

Comment

The SPP Standards Review Group has a concern that the introduction of Phase II at the current state presents confusion on what goals should be accomplished by both SAR(s). From our perspective, we feel that all goals haven't been met with reference to the first SAR and the project shouldn't move forward to the second phase until all Phase I goals have been addressed and resolved.

Likes 0	
Dislikes 0	

Response

Thank you for your response. The revised SAR will allow the Standard Drafting Team address changes required in the original SAR and to review whether another requirement or standard is needed and allows a phased approach to addressing modifications to the existing standard.

sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	

The SAR identified several issues regarding the FRM as the sole measure of frequency response performance. The SAR stated: "The standard must be able to measure all types of Frequency Response and credit the providers. The current standard does not reflect different types of Frequency Response and the timing of such response." Please add the issue regarding the basis of measuring frequency response performance to this ballot.

Joint Owned Units, Pseudo Ties, and Dynamic Schedules that require special consideration when using Net Actual Interchange to determine performance, the Standards Drafting Team should be sure to carefully consider their impacts.

Likes 0	
Dislikes 0	
Response	

Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether modification is necessary to revise the measurement and allocation methodology.

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	

Xcel Energy has concerns that the inclusion of measurements of all types of frequency response may over complicate this standard and become difficult to comply with and enforce.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether modification is necessary to revise the measurement and allocation methodology and undue complexity will be a consideration.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

BPA would like to ensure that NERC considers additional points in the SAR that do not seem to be addressed in the previous questions. These include:

- **Real time reliability and the median measure:** BPA thinks that the BAL-003 standard should be modified to address real - time reliability. By basing performance on the median of events, reliability is not assured. The median has only worked to this point because interconnections have shown historically adequate response. If response declined, and better performance was needed, an increase to the IFRO alone would not assure reliability. Even if the IFRO was increased, there is nothing to dictate that capability must be online for every event to meet the standard. It is possible that that raising the IFRO would only raise the overall median response of the interconnection, while extreme low responses on the interconnection remain. One solution to this is to move to a rolling average of performance as is in the ERCOT BAL-001-TRE standard. This would place more pressure on responsible entities to incentivize performance for every event.
- **Evaluate how frequency response is measured:** Through work done in the WFRSG BPA is aware of many issues related to using NIA in an FRM calculation. These issues are laid out in the technical document supplied by the WFRSG. As well as the issue with the calculation of the FRM, BPA does not think that the FRM should be the sole measure of frequency response. Only by comparing actual

generator performance to NIA can the true response in the BA be determined. BPA also encourages the SDT to evaluate the A to B ratio, compared to a hurdle and bench measurement at the generator level. Equipment can be designed many ways to meet a 20-52 second performance window and do very little for the initial arrest of frequency. Both hurdle and bench performances are important for adequate frequency response. • **The standard only implies a needed capacity:** Frequency response requires both capability and capacity on a resource. This needed capacity is only implied through the standard. BPA believes that more study should be directed at determining the needed frequency response capacity on an interconnection. This capacity should be built into the standard. Without this, BA's in WECC could easily meet the standard by only holding 0.1 Hz worth of frequency response capacity. This is because the large majority of events in WECC are less than 0.1 Hz A to B frequency deviation. • **Event Selection:** Several aspects of BAL-003's event selection and response measurement process may perversely reward poor performance and penalize proper performance. BPA encourages the SDT to evaluate the issues presented in the WFRSG technical document related to these issues. • **Allocation of the IFRO:** BPA encourages the standard drafting team to review the issues laid out in the WFRSG technical document related to the allocation of the IFRO.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review/revise the measurement and allocation methodology.	
Janis Weddle - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Chelan PUD	
Answer	Yes
Document Name	
Comment	

The added cost of the benefits of the SAR should be weighed against the actual benefits of the SAR. This evaluation should include the cost of the time associated with any testing, etc. to meet the added requirements of the SAR.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 2,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	
Comment	
The BAL-003-1.1 SAR technical document focuses on operating characteristics and issues which are largely unique to the Western Interconnection. As stated in the document, the Western Interconnection contains the only FRSG in North America. Although Phase 1 of the SAR could improve the standard (i.e., the calculation of IFRO), it seems the concerns addressed in Phase 2 of the SAR are primarily applicable to the Western Interconnection and its unique FRSG. This suggests a regional standard applicable to the Western Interconnection and its FRSG would be more appropriate for the issues to be addressed in Phase 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether a regional variance, requirement or standard is needed and allow a phased approach to addressing modifications to the existing standard.	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes

Document Name	
Comment	
The compliance obligations stemming from the newly revised BAL-003 standard should be coordinated with the UFLS to ensure the adequate frequency response occurs to rapid arrest the frequency decline and prevent the underfrequency load shedding.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether modification is necessary to revise the measurement and allocation methodology.	
Angela Gaines - Portland General Electric Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Among other issues identified in the SAR regarding the use of FRM as the sole measure of frequency response performance, the SAR stated: "The standard must be able to measure all types of Frequency Response and credit the providers. The current standard does not reflect different types of Frequency Response and the timing of such response." PGE requests the addition of this issue to the ballot.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether modification is necessary to revise the measurement and allocation methodology.	
Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - SERC,RF, Group Name ISO Standards Review Committee	

Answer	Yes
Document Name	
Comment	

The SRC supports the original SAR as proposed to correct inappropriate assumptions in the current standard but does not support this revision of that SAR.

Further the SRC contends:

- There is no explanation in this revision of what to do with the original SAR. If the intent is to proceed with the first phase per the first SAR, then this currently posted SAR should be submitted as an addendum to the first SAR. It is confusing, and inappropriate, to post two SARs addressing in whole or in part of the same proposed tasks.

- Posting this SAR for industry comments may be premature, given that the first phase hasn't been completed and hence changes to the existing BAL-003 are not known. Some of the changes eventually embraced by the industry, adopted by the BoT and approved by regulatory authorities may address part or all of the reliability needs intended by this second SAR.

- The SAR lack evidence of reliability needs/benefits to justify the second phase tasks.

Likes 0	
Dislikes 0	
Response	

Thank you for your response. The revised SAR will allow the Standard Drafting Team address changes required in the original SAR and to review whether another requirement or standard is needed and allows a phased approach to addressing modifications to the existing standard.

Mike Magruder - Avista - Avista Corporation - 1,3,5

Answer	Yes
Document Name	

Comment	
The standard should consider performance in the A to C time period. The present measurement period is A and B. The transition period is not measured. The Western Interconnection is seeing a changing resource mix in a portion of the interconnection. The effects of this change are unknown, and are not being carried out in a planned manner. There is a notable change in the Rate of Change of Frequency (ROCOF) for some events, resulting in faster and deeper A to C frequency changes than have been observed in the past. At some point, it will be necessary for System Operators to have awareness of primary frequency resources available in real time to meet a loss in resources and stabilize frequency. Primary frequency response can be provided by many resources. An awareness of its availability and location enhances reliable system operations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to revise the measurement and allocation methodology.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
PJM believes the effort should continue on the original SAR submitted by the NERC RS. This will offer the opportunity to rectify the existing defects in the current BAL-003 standard and provide an accurate baseline performance of frequency response among the BAAs and Interconnections. PJM does see merit in some of the technical arguments presented in the supplemental SAR; namely exploring a capability requirement for all generators and real-time monitoring. PJM would support these issues being worked following completion of the existing SAR, in whatever capacity deemed appropriate (modification to BAL-003, modification/creation of a different standard).	

Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed and allow a phased approach to addressing modifications to the existing standard.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
The IESO supports the original SAR (proposed by the NERC RS and posted in June/July of this year) to correct inappropriate assumptions in the current standard. If this SAR is intended to replace or supplement the original SAR, then the following process issues arise: • There lacks clarity as to what may happen to the first SAR. If the intent is to proceed with the first phase per the first SAR, then this currently posted SAR should be submitted as an addendum to the first SAR. It is confusing, and inappropriate, to post 2 SARs addressing in whole or in part of the same proposed project. • Posting this SAR for industry comment may be premature, given that the first phase hasn't yet been completed and hence changes to the existing BAL-003 are not known. Some of the changes eventually embraced by the industry, adopted by the BoT and approved by regulatory authorities may address part or all of the reliability needs intended by the second phase. • The SAR lacks evidence of reliability needs/benefits to justify the second phase tasks.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed and allow a phased approach to addressing modifications to the existing standard.	

Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
The phased approach needs to be two distinctive processes. We should not delay the correction proposed in phase I to incorporate any proposed modifications that are noted in phase II. This SAR needs to address only the changes required after modifications of Phase I are complete.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed and allow a phased approach to addressing modifications to the existing standard.	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT takes no position on this SAR; however, if any issues from the 2nd SAR are to be explored further, ERCOT recommends they be addressed by the existing standard drafting team under the existing project rather than expanded into another SDT/project.	
Likes 0	
Dislikes 0	
Response	

Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed and allow a phased approach to addressing modifications to the existing standard.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
AZPS is concerned about the clear intent to cure market issues through revisions to reliability standards. It further is concerned about the lack of justification, specificity, and supporting technical information or data provided in the SAR. Such ambiguity does not provide registered entities with the necessary data to form rigorous, comprehensive comments.	
Likes 0	
Dislikes 0	
Response	
SDT appreciates your comment and disagrees with the premise of market issues and asserts that the current BAL-003-1.1 standard is a reliability standard and commercial issues are outside the scope of the current standard.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
The stated intent of the standard is to assure adequate frequency response for the interconnection to avoid under frequency load shedding for large events. As currently written this standard: {C}1) Does not require any frequency response for large events	

{C}2) Could allow multiple under frequency load shedding events each year without any individual entity failing compliance {C}3) Contains no requirement to maintain frequency responsive reserves {C}4) Creates an inaccurate frequency response measurement, and then allocates that measurement to entities that have no authority to require frequency response {C}5) Tricks BAA's into thinking they are providing frequency response due to the "FRM" calculation method Because of this PacifiCorp believes the standard falls short of meeting its stated intent, and a thorough review is warranted.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address other entities and to review/revise the measurement methodology.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
A better approach for this SAR (phase II) would be to separate it from the existing tightly scoped SAR. This allows the flexibility to potentially develop a separate standard directed toward the more appropriate FM entities.	
Likes 0	
Dislikes 0	
Response	

Thank you for your response. The revised SAR will allow the Standard Drafting Team address changes required in the original SAR and to review whether inclusion of additional applicable entities is warranted and allows a phased approach to addressing modifications to the existing standard.	
Joe Tarantino - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
The SAR identified several issues regarding the FRM as the sole measure of frequency response performance. The SAR stated: "The standard must be able to measure all types of Frequency Response and credit the providers. The current standard does not reflect different types of Frequency Response and the timing of such response." The use of "Net Actual Interchange" may not be the best dataset for FRM. When a frequency deviation occurs due to loss of a large generator or RAS actions, generator governors respond automatically to the resulting drop in frequency. If a BAA is electrically between a large resource providing frequency response and the lost generation, transmission flows can increase on the intermediary BAA's system. As transmission flows increase, transmission line losses increase as well. These losses appear as increased load on the intermediary BAA's system, which can in turn affect apparent FRM performance. In some instances, even though the BAA's generation and load response is appropriate, the losses incurred due to neighboring generator response can overwhelm the BAAs actual FRM.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether modification is necessary to revise the measurement and allocation methodology.	
Yvonne McMackin - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes
Document Name	
Comment	

Grant PUD is not convinced that measuring response in the 10-20 second time frame is better than using the 20-52 second timeframe. Careful evaluation needs to be performed to determine the ideal timeframe to measure response. The best timeframe to measure response may depend on the method chosen to quantify the response.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review/revise the measurement methodology.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
The Phase II section of the SAR identifies the most important changes that need to occur for the BAL-003-1.1 standard to truly address reliability. Phase II addresses the need for using real-time measurements of frequency performance, the need to update the applicability of the standard, and the need for correct market signals.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address other entities and to review/revise the measurement methodology.	
James Ramos - Turlock Irrigation District - 1,3,4,5,6	
Answer	Yes
Document Name	

Comment	
The current BAL-003-1.1 standard does not reflect different types of Frequency Response and the timing of such response." Please add the issue regarding the basis of measuring frequency response performance to this ballot.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review/revise the measurement methodology.	
Antonio Franco - Gridforce Energy Management, LLC - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Gridrforce Energy Management would like to request the drafting team to consider the following: - Allocating FRO based on BA's real time generation plus load (similar to the way CRO is calculated in the Western Interconnection). - Re-evaluate and establish a more realistic window for calculating Primary Frequency Response (currently set between T+20 to T+52 seconds). - Frequency Bias Setting is used by Balancing Authorities for regulation or secondary frequency response purposes. Therefore, FBS should not be calculated solely based on primary frequency response performance, which only generator governors and load are capable of prividing to arrest and stabilize system frequency.	
Likes 0	
Dislikes 0	
Response	

Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address other entities and to review/revise the measurement methodology.	
Theresa Rakowsky - Puget Sound Energy, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
PSE considers BAL-003-1.1 to be unduly discriminatory. To address reliability, BAL-003-1.1 should be modified to impose requirements on individual generating owners' facilities and not burden Balancing Authorities with the cost of 1) procuring frequency response in the market or 2) incurring extensive administrative legal costs through separate, individual Generation Interconnection Agreements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether another requirement or standard is needed to address other entities.	
Dori Quam - NorthWestern Energy - 1 - WECC	
Answer	Yes
Document Name	
Comment	
The SAR identified several issues regarding the FRM as the sole measure of frequency response performance. The SAR stated: "The standard must be able to measure all types of Frequency Response and credit the providers. The current standard does not reflect different types of Frequency Response and the timing of such response." Please add the issue regarding the basis of measuring frequency response performance to this ballot. The SAR for BAL-003-1.1 should specify and require strict parameters for the selection of FRR events used for compliance requirements. This would be similar to the BAL-002 parameters used for DCS event selection.	

Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether modification is necessary to revise the measurement and allocation methodology.	
Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	
AEP is not in agreement with the Phase II content of the BAL-003 SAR. AEP suggests the SDT recommend that the content of Phase II SAR for BAL-003 instead be considered for a ***regional*** Reliability Standard based on the examples provided in the supporting document "Standards Authorization Request Revision to BAL-003-1.1 Frequency Response and Frequency Bias Setting June 28, 2017", since the other interconnections are not experiencing the issues brought forth.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether a regional variance, requirement or standard is needed and allow a phased approach to addressing modifications to the existing standard.	
Casey Johnston - Concerned Electrical Engineer with 40 yrs in Electrical Industry - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

The SAR identified several issues regarding the FRM as the sole measure of frequency response performance. The SAR stated: "The standard must be able to measure all types of Frequency Response and credit the providers. The current standard does not reflect different types of Frequency Response and the timing of such response." Please add the issue regarding the basis of measuring frequency response performance to this ballot. The SAR for BAL-003-1.1 should specify and require strict parameters for the selection of FRR events used for compliance requirements. This would be similar to the BAL-002 parameters used for DCS event selection.

In my professional experience, BAL-003-1.1 is the most poorly written and is the only retrospective standard, since the creation of the current NERC Mandatory standard system in 2006. The Standard needs to be rewritten and the deficiencies corrected

Likes 0	
Dislikes 0	
Response	
Thank you for your response. The revised SAR will allow the Standard Drafting Team to review whether modification is necessary to revise the measurement and allocation methodology.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE requests the SDT consider adding language to the standard to address the process for exclusions in Attachment 1, including the entity responsible for granting exclusions and the documentation required (such as corrective action plans) when requesting an exclusion.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SAR drafting team will recommend the STD take your comment into consideration during the drafting phase of this project.

Unofficial Nomination Form

Project 2017-01 Modifications to BAL-003-1.1 Standard Drafting Team

Do not use this form for submitting nominations. Use the electronic form to submit nominations by **8 p.m. Eastern, Wednesday, March 28, 2018.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Additional information about this project is available on the Project 2017-01 Modifications to BAL-003-1.1 page. If you have questions, contact Principal Technical Advisor Darrel Richardson, (via email), or at (609) 613-1848 or Standards Developer, Laura Anderson (via email), or at (404) 446-9671.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

Previous drafting or periodic review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below.

Project 2017-01 Modifications to BAL-003-1.1

The purpose of this project is to review the issues identified in the SAR and make corresponding modifications to BAL-003-1.1, as necessary.

Standards affected: BAL-003-1 and BAL-003-1.1

The supporting documents for BAL-003-1.1 were developed using engineering judgment on the data collection and process needed to determine the Interconnection Frequency Response Obligation (IFRO), as well as the processing of raw data to determine compliance. Now that the Reliability Standard is in place and the data is available for analyses, minor errors in assumptions, as well as process, inefficiencies have been identified. It was anticipated that as Frequency Response improves, the approaches embedded in the Reliability Standard for annual samples may need to be modified. In addition to fixing the inconsistencies identified in the Frequency Response Annual Analysis Report (FRAA), the drafting team may separate the administrative and procedural items and reassign them to an alternative process, subject to Electric Reliability Organization (ERO) and North American Electric Reliability Corporation (NERC) Operating Committee approval.

The time commitment for this project is expected to be up to two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed-upon timeline that the review or drafting team sets forth. Team members may also have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the review and drafting team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

We are seeking three (3) to four (4) additional members from the industry to participate on the drafting team; but in particular, we are seeking individuals who have experience and expertise in the generator segment of the industry. Experience with developing standards inside or outside (e.g., IEEE, NAESB, ANSI, etc.) of the NERC process is beneficial, but is not required, and should be highlighted in the information submitted, if applicable.

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	

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

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

Select each Industry Segment that you represent:	
☐	1 — Transmission Owners
☐	2 — RTOs, ISOs
☐	3 — Load-serving Entities
☐	4 — Transmission-dependent Utilities
☐	5 — Electric Generators
☐	6 — Electricity Brokers, Aggregators, and Marketers
☐	7 — Large Electricity End Users
☐	8 — Small Electricity End Users
☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	NA – Not Applicable

Select each Function[1] in which you have current or prior expertise:	
☐ Balancing Authority	☐ Transmission Operator
☐ Compliance Enforcement Authority	☐ Transmission Owner
☐ Distribution Provider	☐ Transmission Planner
☐ Generator Operator	☐ Transmission Service Provider
☐ Generator Owner	☐ Purchasing-selling Entity
☐ Interchange Authority	☐ Reliability Coordinator
☐ Load-serving Entity	☐ Reliability Assurer
☐ Market Operator	☐ Resource Planner
☐ Planning Coordinator	

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

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	
Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

Standards Announcement

Project 2017-01 Modifications to BAL-003-1.1

Drafting Team Nomination Period Open through March 28, 2018

Now Available

Additional nominations are being sought for members of the Project 2017-01 Modifications to BAL-003-1.1 standard drafting team through **8 p.m. Eastern, Wednesday, March 28, 2018**.

Use the electronic form to submit a nomination. If you experience any difficulties using the electronic form, contact Nasheema Santos. An unofficial Word version of the nomination form is posted on the Standard Drafting Team Vacancies page and the project page.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in face-to-face meetings and conference calls.

The time commitment for this project is expected to be two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed upon timeline the team sets forth. Team members may also have side projects, either individually or by sub-group, to present for discussion and review. Lastly, an important component of the standard drafting team (SDT) effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful ballot.

We are seeking three (3) to four (4) additional members from the industry to participate on the standard drafting team; but in particular, we are seeking individuals who have experience and expertise in the generator segment of the industry. Experience with developing standards inside or outside (e.g., IEEE, NAESB, ANSI, etc.) of the NERC process is beneficial, but is not required, and should be highlighted in the information submitted, if applicable.

Previous drafting team experience is beneficial but not required. See the project page and nomination form for additional information.

Next Steps

NERC staff will present nominations to the Standards Committee in April 2018. Nominees will be notified shortly after the appointments have been made.

For information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Laura Anderson (via email), or at (404) 446-9671 or Principal Technical Advisor, Darrel Richardson (via email) or at (609) 613-1848.

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Atlanta, GA 30326
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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Authorization Request Form

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

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

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	BAL-003-1.1 – Frequency Response and Frequency Bias Setting		
Date Submitted:			
SAR Requester Information			
Name:	David Lemmons – Chair of the Project 2017-01 BAL3 SAR Drafting Team		
Organization:	Project 2017-01 BAL3 SAR Drafting Team		
Telephone:	303.807.7949	Email:	David.Lemmons@ethosenergygroup.com
SAR Type (Check as many as applicable)			
☐ New Standard ☒ Revision to Existing Standard		☐ Withdrawal of Existing Standard ☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The revisions to this standard are proposed to be approached in phases; however, the Standard Drafting Team (SDT) will determine the priority for each of the specific tasks. The revisions proposed in Phase I are intended only to correct inconsistencies identified through implementation of the standard and to improve efficiencies and effectiveness of the administration associated with the standard. Revisions proposed for Phase II are modifications intended to align the standard more closely with its purpose. **Phase I**

SAR Information
The supporting documents for BAL-003-1.1 were developed using engineering judgment on the data collection and process needed to determine the interconnection Frequency Response Obligation (IFRO), as well as the processing of raw data to determine compliance. Now that the standard is in place and the data is available for analysis, minor errors in assumptions, as well as process inefficiencies, have been identified. It is expected that as Frequency Response improves, the approaches embedded in the standard for annual samples may need to be modified. The items that need to be addressed are to: • Revise the IFRO calculation in BAL-003-1 due to issues identified in the [2016 Frequency Response Annual Analysis (FRAA) Report](), such as the IFRO values with respect to Point C and varying Value B; • Reevaluate the interconnections' Resource Contingency Protection Criteria; • Reevaluate the frequency nadir point limitations (currently limited to t_0 to t+12); • Review and modify as necessary Attachment A of the Reliability Standard to remove administrative tasks and provide additional clarity, e.g., related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities; and • Make enhancements to the BAL-003-1.1 FRS Forms that include, but may not be limited to, the ability to collect and submit FRSG performance data. In addition to fixing the inconsistencies outlined above, the SDT may separate the administrative and procedural items and propose that they be reassigned to an alternative process subject to Electric Reliability Organization (ERO) and North American Electric Reliability (NERC) Operating Committee approval. **Phase II** The intent of the Reliability Standard is to ensure sufficient Frequency Response for each interconnection. Allocation of the responsibility to provide Frequency Response needs to reflect current conditions of the grid and correspond with the entities which provide and/or coordinate its provision. • Both the IFRO calculations and the allocation of IFROs to reliability entities are retrospective (up to 2 years). The review should determine if there are alternate methodologies which consider characteristics affecting Frequency Response (e.g., load response, mix and type of generation, Balancing Authority Area (BAA) footprint changes) to make allocation as equitable as possible; • Although Balancing Authorities (BAs) and FRSGs are responsible for coordination and/or management of Frequency Response from both resources and loads, response from resources is not addressed. The review should determine if additional reliability entities should have

SAR Information
responsibility (e.g., Generator Operators (GOPs)) for provision of generator governor response; and • Review the measurement methodology of Frequency Response (both System and equipment level): o The Frequency Response Measure (FRM) should be reviewed to ensure that over-performance by one entity does not negatively impact the evaluation of performance by another.
Purpose or Goal (How does this request propose to address the problem described above?):
Phase I Review and revise the BAL-003-1.1 Reliability Standard and process documents to address the items listed in Phase I above. Additionally, the SDT should consider removing the supporting procedural and administrative processes from Attachment A for incorporation into ERO-approved reference document(s) such that timely process improvements can be made as future lessons are learned. For additional information, please refer to the 2016 FRAA Report. **Phase II** Review and revise the BAL-003-1.1 Reliability Standard subsequent to Phase I and process documents to address the items listed in Phase II above.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
To address the issues with the Reliability Standard referenced above, including those that were described in the 2016 FRAA Report.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
Phase I During the 2016 annual evaluation of the values used in the calculation of the IFRO, the above-mentioned issues listed under Phase I were identified. The scope of the work will be to (1) address the inconsistency in the ratio of Point C to Value B, (2) reevaluate the Resource Contingency Protection Criteria for each interconnection, (3) reevaluate the frequency nadir point limitations (currently limited to t_0 to t+12), (4) clarify language in Attachment A, and (5) make enhancements to the BAL-003-1.1 FRS Forms that include, but may not be limited to, the ability to collect and submit FRSG performance data and identify opportunities to make current processes more efficient. For additional information on items #1, 2 and 3, please refer to the 2016 FRAA Report.

SAR Information
Phase II The scope of the work will be to (1) revise the Reliability Standard to address the Real-time aspects of Frequency Response necessary to maintain reliability, (2) ensure comparability of and applicability to the appropriate responsible entities, (3) develop measurements to incorporate Real-time and resource and load characteristics, and (4) ensure equitability of performance measurement.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Phase I Consider revising the BAL-003-1.1 Reliability Standard concerning Bullet 1 of Phase I above through the standards development process to correct the inconsistency in the ratio of Point C to Value B. According to the FRAA Report, this ratio in the IFRO calculation couples Point C and Value B together, resulting in IFRO trends that do not align with the intent of the standard. Improvement in Value B with no change in Point C (improving recovery phase) would result in higher obligations to be carried, essentially penalizing improved recovery performance. Consider revising the BAL-003-1.1 Reliability Standard concerning Bullet 2 of Phase I above through the standards development process to modify the Resource Contingency Protection Criteria (RCPC). The RCPC for each interconnection should be revised to help ensure sufficient primary frequency response is maintained. The Eastern Interconnection uses the "largest resource event in last 10 years," which is the August 4, 2007 event. The SDT should revisit this issue for modifications to the BAL-003-1 Reliability Standard, and the Resources Subcommittee (RS) should recommend the criteria used to identify events for each interconnection. Consider revising the BAL-003-1.1 Reliability Standard concerning Bullet 3 of Phase I above through the standards development process to revisit the frequency nadir point used in the calculation. Many events, particularly in the Eastern Interconnection due to its large synchronous inertia, tend to have a frequency nadir point that exceeds the t_0 +12 seconds specified in BAL-003-1. Therefore, some events are characterized with a Point C value that is only partially down the arresting period of the event and does not accurately reflect the actual nadir. BAL-003-1 should be modified to allow for accurate representation of the Point C nadir value if exceeding beyond t_0+12 seconds. The actual event nadir can occur at any time, including beyond the time period used for calculating Value B (t_0+20 through t_0+52 seconds) and may be the value known as Point C' which typically occurs in the 72 to 95 second range after t_0.

SAR Information
Consider revising BAL-003-1.1 Attachment A to provide clarity of intent giving particular attention to FRSGs and the timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities. Consider transferring supporting procedural and process steps from Attachment A into an ERO and NERC Operating Committee approved Reference Document or Reliability Guideline. Consider revising the BAL-003-1.1 Reliability Standard concerning Bullet 5 of Phase I above through the standards development process to provide enhancements of the FRS Forms that include, but may not be limited to, the ability to collect and submit FRSG performance data. **Phase II** Consider revising the BAL-003-1.1 Reliability Standard to: • Make the IFRO calculations and associated allocations 1) more reflective of current conditions, 2) consider all characteristics affecting Frequency Response (e.g., load response, mix and type of generation), 3) include all applicable entities, and 4) be as equitable as possible; and • Make the FRM 1) ensure that over-performance by one entity does not negatively impact the evaluation of performance by another, 2) measure types/periods of response in addition to secondary Frequency Response, particularly primary Frequency Response, 3) include all applicable entities, and 4) make allocations as equitable as possible.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☐ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator’s wide area view.
☒ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports interconnection frequency in real time.

Reliability Functions		
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the end-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the end-use customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Reliability and Market Interface Principles	
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

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

Related Standards	
Standard No.	Explanation
MOD-027-1	This standard applies to GOPs and requires verification of Turbine/Governor and Load Control or Active Power/Frequency Control Functions. Modifications to the BAL-003-1.1 Reliability Standard will need to coordinate with/complement MOD-027-1 to ensure there is no overlap or gap of requirements for governor performance.

Related Standards	
EOP-005-2	Consider impacts to EOP-005-2.
BAL-001-TRE-1	Consider impacts to BAL-001-TRE-1.

Related SARs	
SAR ID	Explanation
None	

Regional Variances	
Region	Explanation
ERCOT	None.
FRCC	None.
MRO	None.
NPCC	None.
RFC	None.
SERC	None.
SPP	None.

Regional Variances	
WECC	None.

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template

Standards Authorization Request Form

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

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

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	BAL-003-1.1 – Frequency Response and Frequency Bias Setting		
Date Submitted:			
SAR Requester Information			
Name:	David Lemmons – Chair of the Project 2017-01 BAL3 SAR Drafting Team		
Organization:	Project 2017-01 BAL3 SAR Drafting Team		
Telephone:	303.807.7949	Email:	David.Lemmons@ethosenergygroup.com
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of Existing Standard	
☒ Revision to Existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
The revisions to this standard are proposed to be approached in phases; however, the Standard Drafting Team (SDT) will determine the priority for each of the specific tasks. The revisions proposed in ~~the first~~ ~~p~~Phase I are intended only to correct inconsistencies identified through ~~use~~ implementation of the standard and to improve efficiencies and effectiveness of the administration associated with the standard. Revisions proposed for ~~the second~~ Pphase II are modifications intended to align the standard more closely with its purpose.

SAR Information
Phase I The supporting documents for BAL-003-1.1 were developed using engineering judgment on the data collection and process needed to determine the interconnection Frequency Response Obligation (IFRO), as well as the processing of raw data to determine compliance. Now that the standard is in place and the data is available for analysis, minor errors in assumptions, as well as process inefficiencies, have been identified. It is expected that as Frequency Response improves, the approaches embedded in the standard for annual samples may need to be modified. ~~In addition to fixing the inconsistencies outlined below, the drafting team may separate the administrative and procedural items and reassign them to an alternative process subject to Electric Reliability Organization (ERO) and North American Electric Reliability (NERC) Operating Committee approval.~~ The items that need to be addressed are to: • Revise the IFRO calculation in BAL-003-1 due to issues identified in the 2016 Frequency Response Annual Analysis (FRAA) Report, such as the IFRO values with respect to Point C and varying Value B; • Reevaluate the interconnections' Resource Contingency Protection Criteria; • Reevaluate the frequency nadir point limitations (currently limited to t_0 to t+12); • Review and modify as necessary Attachment A of the Reliability Standard to remove administrative tasks and provide additional clarity, e.g., related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities; and • Make enhancements to the BAL-003-1.1 FRS Forms that include, but may not be limited to, the ability to collect and submit FRSG performance data. In addition to fixing the inconsistencies outlined above, the SDT may separate the administrative and procedural items and propose that they be reassigned to an alternative process subject to Electric Reliability Organization (ERO) and North American Electric Reliability (NERC) Operating Committee approval. **Phase II** The intent of the Reliability Standard is to ensure sufficient Frequency Response for each interconnection. Allocation of the responsibility to provide Frequency Response needs to reflect current conditions of the grid and correspond~~be commensurate~~ with the entities which provide and/or coordinate its provision. • Both the IFRO calculations and the allocation of IFROs to reliability entities are retrospective (up to 2 years). The review should determine if there are alternate methodologies which consider

SAR Information
characteristics affecting Frequency Response (e.g., load response, mix and type of generation, Balancing Authority Area (BAA) footprint changes) to make allocation as equitable as possible; • Although Balancing Authorities (BAs) and FRSGs are responsible for coordination and/or management of Frequency Response from both resources and loads, response from resources is not addressed. The review should determine if additional reliability entities should have responsibility (e.g., Generator Operators (GOPs)) for provision of generator governor response~~)~~; and • Review the measurement methodology of Frequency Response (both System and equipment level): o The Frequency Response Measure (FRM) should be reviewed to ensure that over-performance by one entity does not negatively impact the evaluation of performance by another.
Purpose or Goal (How does this request propose to address the problem described above?):
Phase I Review and revise the BAL-003-1.1 Reliability Standard and process documents to address the items listed in Phase I above. Additionally, the SDT should consider removing the supporting procedural and administrative processes from Attachment A ~~shall be considered~~ for incorporation into ERO-approved reference document(s) such that timely process improvements can be made as future lessons are learned. For additional information, please refer to the 2016 FRAA Report. **Phase II** Review and revise the BAL-003-1.1 Reliability Standard subsequent to Phase I and process documents to address the items listed in Phase II above.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
To address the issues with the Reliability Standard referenced above, including those that were described in the 2016 FRAA Report.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
Phase I During the 2016 annual evaluation of the values used in the calculation of the IFRO, the above-mentioned issues listed under Phase I were identified. The scope of the work will be to (1) address the inconsistency in the ratio of Point C to Value B, (2) reevaluate the Resource Contingency Protection

SAR Information
Criteria for each interconnection, (3) reevaluate the frequency nadir point limitations (currently limited to t_0 to t+12), (4) clarify language in Attachment A, and (5) make enhancements to the BAL-003-1.1 FRS Forms that include, but may not be limited to, the ability to collect and submit FRSG performance data and identify opportunities to make current processes more efficient. For additional information on items #1, 2 and 3, please refer to the 2016 FRAA Report. **Phase II** The scope of the work will be to (1) revise the Reliability Standard to address the Real-time aspects of Frequency Response necessary to maintain reliability, (2) ensure comparability of and applicability to the appropriate responsible entities, (3) develop measurements to incorporate Real-time and resource and load characteristics, and (4) ensure equitability of performance measurement.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
Phase I Consider revising the BAL-003-1.1 Reliability Standard concerning Bullet 1 of Phase I above through the standards development process to correct the inconsistency in the ratio of Point C to Value B. According to the FRAA Report, this ratio in the IFRO calculation couples Point C and Value B together, resulting in IFRO trends that do not align with the intent of the standard. Improvement in Value B with no change in Point C (improving recovery phase) would result in higher obligations to be carried, essentially penalizing improved recovery performance. Consider revising the BAL-003-1.1 Reliability Standard concerning Bullet 2 of Phase I above through the standards development process to modify the Resource Contingency Protection Criteria (RCPC). The RCPC for each interconnection should be revised to help ensure sufficient primary frequency response is maintained. The Eastern Interconnection uses the "largest resource event in last 10 years," which is the August 4, 2007 event. The ~~standard drafting team~~SDT should revisit this issue for modifications to the BAL-003-1 Reliability Standard, and the Resources Subcommittee (RS) should recommend ~~how~~ the criteria used to identify events ~~are selected~~ for each interconnection. Consider revising the BAL-003-1.1 Reliability Standard concerning Bullet 3 of Phase I above through the standards development process to revisit the frequency nadir point used in the calculation. Many events, particularly in the Eastern Interconnection due to its large synchronous inertia, tend to have a

SAR Information

frequency nadir point that exceeds the t_0 +12 seconds specified in BAL-003-1. Therefore, some events are characterized with a Point C value that is only partially down the arresting period of the event and does not accurately reflect the actual nadir. BAL-003-1 should be modified to allow for accurate representation of the Point C nadir value if exceeding beyond t_0+12 seconds. The actual event nadir can occur at any time, including beyond the time period used for calculating Value B (t_0+20 through t_0+52 seconds) and may be the value known as Point C' which typically occurs in the 72 to 95 second range after t_0.

Consider revising BAL-003-1.1 Attachment A to provide clarity of intent giving particular attention to FRSGs and the timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities. Consider transferring supporting procedural and process steps from Attachment A into an ERO and NERC Operating Committee approved Reference Document or Reliability Guideline.

Consider revising the BAL-003-1.1 Reliability Standard concerning Bullet 5 of Phase I above through the standards development process to provide enhancements of the FRS Forms that include, but may not be limited to, the ability to collect and submit FRSG performance data.

Phase II

Consider revising the BAL-003-1.1 Reliability Standard to:

- Make the IFRO calculations and associated allocations 1) ~~be~~ more reflective of current conditions, 2) consider all characteristics affecting Frequency Response (e.g., load response, mix and type of generation), 3) include all applicable entities, and 4) be as equitable as possible; and
- Make the FRM 1) ensure that over-performance by one entity does not negatively impact the evaluation of performance by another, 2) measure types/periods of response in addition to secondary Frequency Response, particularly primary Frequency Response, 3) include all applicable entities, and 4) make allocations as equitable as possible.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the end-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.

Reliability Functions	
☐ Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the end-use customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☒	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

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

Related Standards	
Standard No.	Explanation
MOD-027-1	This standard applies to GOPs and requires verification of Turbine/Governor and Load Control or Active Power/Frequency Control Functions. Modifications to the BAL-003-1.1 Reliability Standard will need to coordinate with/complement MOD-027-1 to ensure there is no overlap or gap of requirements for governor performance.
EOP-005-2	Consider impacts to EOP-005-2.
BAL-001-TRE-1	Consider impacts to BAL-001-TRE-1.

Related SARs	
SAR ID	Explanation
None	

Regional Variances	
Region	Explanation
ERCOT	None.
FRCC	None.

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

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

15-day informal comment period

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	04/18/2018
SAR posted for comment	03/19/18 – 03/28/18

Anticipated Actions	Date
~~XX~~45-day formal or informal comment period with ballot	TBD
~~XX~~45-day formal or informal comment period with additional ballot	TBD
~~XX~~10-day final ballot	TBD
Board adoption	TBD

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title: Frequency Response and Frequency Bias Setting**

2. **Number:** BAL-003-~~1.1~~2

3. **Purpose:** To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authority

   4.1.1.1. Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.

   4.1.2. Frequency Response Sharing Group

5. **Effective Date:** See Implementation Plan for BAL-003-~~1.1~~2.

B. Requirements and Measures

R1. Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) 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. *[Risk Factor: High][Time Horizon: Real-time Operations]*

M1. Each Frequency Response Sharing Group or Balancing Authority that is not a member of a Frequency Response Sharing Group shall have evidence such as dated data plus documented formula in either hardcopy or electronic format that it achieved an annual FRM (in accordance with the methods specified by the ERO in Attachment A with data from FRS Form 1 reported to the ERO as specified in Attachment A) that is equal to or more negative than its FRO to demonstrate compliance with Requirement R1.

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 in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. *[Risk Factor: Medium][Time Horizon: Operations Planning]*

M2. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service shall have evidence such as a dated document in hard copy or electronic format showing the ERO validated Frequency Bias Setting was implemented into its ACE calculation within the implementation period specified or other evidence to demonstrate compliance with Requirement R2.

R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

3.1 Less than zero at all times, and

3.2 Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.

M3. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and is utilizing variable Frequency Bias shall have evidence such as a dated report in hard copy or electronic format showing the average clock-minute average Frequency Bias Setting was less than zero and during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was equal to or more negative than its Frequency Response Obligation to demonstrate compliance with Requirement R3.

R4. 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 to either: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

- The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or
- The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.

M4. The Balancing Authority shall have evidence such as a dated operating log, database or list in hard copy or electronic format showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation as specified in Requirement R4 to demonstrate compliance with Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

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

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If a Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.
- The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or

information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

- For Interconnections that are also Balancing Authorities, Tie Line Bias control and flat frequency control are equivalent and either is acceptable.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1% but by at most ~~30~~15% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 15% but by at most 30% or by more than ~~15~~ 30 MW/0.1 Hz, whichever is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than ~~1~~30% but by at most ~~30~~45% or ~~15~~ 45 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than ~~30~~45% or by more than ~~15~~ 45 MW/0.1 Hz, whichever is the greater deviation from its FRO.
R2.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting failed to implement the validated Frequency Bias Setting value into its ACE calculation within the implementation period specified but did so within 5 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 5 calendar days but less than or equal to 15 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 15 calendar days but less than or equal to 25 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting did not implement the validated Frequency Bias Setting value into its ACE calculation in more than 25 calendar days from the implementation period specified by the ERO.

R3.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 1% but by at most 10%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 10% but by at most 20%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 20% but by at most 30%.	The Balancing Authority that is a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response obligation by more than 30%.
R4.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error less than or equal to 10% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 10% but less than or equal to 20% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 20% but less than or equal to 30% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 30% of the validated or calculated value. OR The Balancing Authority failed to change the Frequency Bias Setting value

				used in its ACE calculation when providing Overlap Regulation Services.

D. Regional Variances

None.

E. Associated Documents

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

FRS Form 1

FRS Form 2

Frequency Response Standard Background Document

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	March 16, 2007	FERC Approval — Order 693	New
0a	December 19, 2007	Added Appendix 1 — Interpretation of R3 approved by BOT on October 23, 2007	Addition
0a	July 21, 2008	FERC Approval of Interpretation of R3	Addition
0b	February 12, 2008	Added Appendix 2 — Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition
0.1b	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial; updated version number to “0.1b”	Errata
0.1b	October 29, 2008	BOT approved errata changes	Errata
0.1a	May 13, 2009	FERC Approved errata changes – version changed to 0.1a (Interpretation of R2, R2.2, R5, and R5.1 not yet approved)	Errata
0.1b	May 21, 2009	FERC Approved Interpretation of R2, R2.2, R5, and R5.1	Addition
1	February 7, 2013	Adopted by NERC Board of Trustees	Complete Revision under Project 2007-12
1	January 16, 2014	FERC Order issued approving BAL-003-1. (Order becomes effective for R2, R3, and R4 April 1, 2015. R1 becomes effective April 1, 2016.)	
1	May 7, 2014	NERC Board of Trustees adopted revisions to VRF and VSLs in Requirement R1.	
1	November 26, 2014	FERC issued a letter order approved VRF and VSL revisions to Requirement R1.	
1.1	August 25, 2015	Added numbering to Introduction section, corrected parts numbering for R3, and adjusted font within section M4.	Errata

Version	Date	Action	Change Tracking
1.1	November 13, 2015	FERC Letter Order approved errata to BAL-003-1.1. Docket RD15-6-000	Errata

Standard Attachments

Attachment A

BAL-003-1 Frequency Response & Frequency Bias Setting Standard

Supporting Document

~~Interconnection Frequency Response Obligation (IFRO)~~

~~The ERO, in consultation with regional representatives, has established a target contingency protection criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). The default IFRO listed in Table 1 is based on the resource contingency criteria (RCC), which is the largest category C (N-2) event identified except for the Eastern Interconnection, which uses the largest event in the last 10 years. A maximum delta frequency (MDF) is calculated by adjusting a starting frequency for each Interconnection by the following:~~

~~Prevailing UFLS first step~~

- ~~CC_{Adj} which is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data~~
- ~~CB_R which is the statistically determined ratio of the Point C to Value B~~
- ~~BC'_{Adj} which is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.~~

~~The IFRO for each Interconnection in Table 1 is then calculated by dividing the RCC MWs by 10 times the MDF. In the Eastern Interconnection there is an additional adjustment (BC'_{Adj}) for the event nadir being below the Value B due to primary frequency response withdrawal. This IFRO includes uncertainty adjustments at a 95 % confidence level. Detailed descriptions of the calculations used in Table 1 below are defined in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.*~~

~~Interconnection~~	~~**Eastern**~~	~~**Western**~~	~~**ERCOT**~~	~~**HQ**~~	~~Units~~
~~Starting Frequency (F_{Start})~~	~~**59.974**~~	~~**59.976**~~	~~**59.963**~~	~~**59.972**~~	~~Hz~~
~~Prevailing UFLS First Step~~	~~**59.5***~~	~~**59.5**~~	~~**59.3**~~	~~**58.5**~~	~~Hz~~
~~Base Delta Frequency (DF_{Base})~~	~~**0.474**~~	~~**0.476**~~	~~**0.663**~~	~~**1.472**~~	~~Hz~~
~~CC_{ADJ}~~	~~**0.007**~~	~~**0.004**~~	~~**0.012**~~	~~**N/A**~~	~~Hz~~
~~Delta Frequency (DF_{CC})~~	~~**0.467**~~	~~**0.472**~~	~~**0.651**~~	~~**1.472**~~	~~Hz~~
~~CB_R~~	~~**1.000**~~	~~**1.625**~~	~~**1.377**~~	~~**1.550**~~	
~~Delta Frequency (DF_{CBR})~~	~~**0.467**~~	~~**0.291**~~	~~**0.473**~~	~~**0.949**~~	~~Hz~~
~~BC'_{ADJ}~~	~~**0.018**~~	~~**N/A**~~	~~**N/A**~~	~~**N/A**~~	~~Hz~~
~~Max. Delta Frequency (MDF)~~	~~**0.449**~~	~~**0.291**~~	~~**0.473**~~	~~**0.949**~~	

~~Resource Contingency Criteria (RCC)~~	~~**4,500**~~	~~**2,740**~~	~~**2,750**~~	~~**1,700**~~	~~MW~~
~~Credit for Load Resources (CLR)~~		~~**300**~~	~~**1,400****~~		~~MW~~
~~IFRO~~	~~**-1,002**~~	~~**-840**~~	~~**-286**~~	~~**-179**~~	~~MW/0.1 Hz~~

~~Table 1: Interconnection Frequency Response Obligations~~

*~~*The Eastern Interconnection UFLS set point listed is a compromise value set midway between the stable frequency minimum established in PRC-006-1 (59.3 Hz) and the local protection UFLS setting of 59.7 Hz used in Florida and Manitoba.~~*

*~~**In the Base Obligation measure for ERCOT, 1400 MW (Load Resources triggered by Under Frequency Relays at 59.70 Hz) was reduced from its Resource Contingency Criteria level of 2750 MW to get 239 MW/0.1 Hz. This was reduced to accurately account for designed response from Load Resources within 30 cycles.~~*

~~An Interconnection may propose alternate IFRO protection criteria to the ERO by submitting a SAR with supporting technical documentation.~~

~~Balancing Authority Frequency Response Obligation (FRO) and Frequency Bias Setting~~

~~The ERO will manage the administrative procedure for annually assigning an FRO and implementation of the Frequency Bias Setting for each Balancing Authority. The annual timeline for all activities described in this section are shown below.~~

~~For a multiple Balancing Authority interconnection, the Interconnection Frequency Response Obligation shown in Table 1 is allocated based on the Balancing Authority annual load and annual generation. The FRO allocation will be based on the following method:~~

$$\cancel{\mathrm{FRO_{BA}} = \mathrm{IFRO}\_ \times \frac{\text{Annual Gen}_{\mathrm{BA}} + \text{Annual Load}_{\mathrm{BA}}}{\text{Annual Gen}_{\mathrm{Int}} + \text{Annual Load}_{\mathrm{Int}}}}$$

~~Where:~~

- ~~Annual Gen~~$_{BA}$ ~~is the total annual "Output of Generating Plants" within the Balancing Authority Area (BAA), on FERC Form 714, column c of Part II - Schedule 3.~~
- ~~Annual Load~~$_{BA}$ ~~is total annual Load within the BAA, on FERC Form 714, column e of Part II - Schedule 3.~~
- ~~Annual Gen~~$_{Int}$ ~~is the sum of all Annual Gen~~$_{BA}$ ~~values reported in that interconnection.~~
- ~~Annual Load~~$_{Int}$ ~~is the sum of all Annual Load~~$_{BA}$ ~~values reported in that interconnection.~~

~~The data used for this calculation is from the most recently filed Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which utilized data from 2011.~~

~~Balancing Authorities that are not FERC jurisdictional should use the Form 714 Instructions to assemble and submit equivalent data to the ERO for use in the FRO Allocation process.~~

~~Balancing Authorities that elect to form a FRSG will calculate a FRSG FRO by adding together the individual BA FRO's.~~

~~Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:~~

- ~~Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or~~
- ~~Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that contains the sum of each participant's individual event performance.~~

Balancing Authorities that merge or that transfer load or generation are encouraged to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation to the Interconnection remains the same and so that CPS limits can be adjusted.

Each Balancing Authority reports its previous year's Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised Frequency Bias Settings on FRS Form 1. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities will be given 30 days from the date the ERO posts the official list of events to submit their FRS Form 1.

Once the ERO reviews the data submitted in FRS Form 1 and FRS Form 2 for all Balancing Authorities, the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year:

- Frequency Bias Setting
- Frequency Response Obligation (FRO)

Once the data listed above is fully posted, the ERO will announce the three-day implementation period for changing the Frequency Bias Setting if it differs from that shown in the timeline below.

A BA using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value):

- Any number the BA chooses between 100% and 125% of its Frequency Response Measure as calculated on FRS Form 1
- Interconnection Minimum as determined by the ERO

For purposes of calculating the minimum Frequency Bias Setting, a Balancing Authority participating in a Frequency Response Sharing Group will need to calculate its stand-alone Frequency Response Measure using FRS Form 1 and FRS Form 2 to determine its minimum Frequency Bias Setting.

A Balancing Authority providing Overlap Regulation will report the historic peak demand and generation of its combined BAs' areas on FRS Form 1 as described in Requirement R4.

Balancing Authorities that elect to form a FRSG will calculate a FRSG FRO by adding together the individual BA FRO's.

~~There are occasions when changes are needed to Bias Settings outside of the normal schedule. Examples are footprint changes between Balancing Authorities and major changes in load or generation or the formation of new Balancing Authorities. In such cases the changing Balancing Authorities will work with their Regions, NERC and the Resources Subcommittee to confirm appropriate changes to Bias Settings, FRO, CPS limits and Inadvertent Interchange balances.~~

~~If there is no net change to the Interconnection total Bias, the Balancing Authorities involved will agree on a date to implement their respective change in Bias Settings. The Balancing Authorities and ERO will also agree to the allocation of FRO such that the sum remains the same.~~

~~If there is a net change to the Interconnection total Bias, this will cause a change in CPS2 limits and FRO for other Balancing Authorities in the Interconnection. In this case, the ERO will notify the impacted Balancing Authorities of their respective changes and provide an implementation window for making the Bias Setting changes.~~

Interconnection Frequency Response Obligation (IFRO)

The ERO, in consultation with regional representatives, has established a target contingency protection criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). Detailed descriptions of the IFRO calculations are defined in the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.[1]

Frequency Response Measure (FRM)

The Balancing Authority will calculate its FRM from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event from a Balancing Authority that is used to calculate its Frequency Response, expressed in MW/0.1Hz" as calculated on FRS Form 2 for each event shown on FRS Form 1. The events in FRS Form 1 are selected by the ERO using the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is basically the change in its Net Actual Interchange on its tie lines with its adjacent Balancing Authorities divided by the change in Interconnection frequency. (Some Balancing Authorities may choose to apply corrections to their Net Actual Interchange (NA_I) values to account for factors such as nonconforming loads. FRS Form 1 and 2 shows the types of adjustments that are allowed. Note that with the exception of the Contingent BA column, any adjustments made must be made for all events in an evaluation year. As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.) The ERO will use a standardized sampling interval of approximately 16 seconds before the

[1] Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard is available at https://www.nerc.com/pa/Stand/Frequency%20Response%20Project%20200712%20Related%20Files%20DL/BAL-003-1_Procedure-Clean_20120210.pdf

event up to the time of the event for the pre-event NA_I, and frequency (A values) and approximately 20 to 52 seconds after the event for the post-event NA_I (B values) in the computation of SEFRD values, dependent on the data scan rate of the Balancing Authority's Energy Management System (EMS).

All events listed on FRS Form 1 need to be included in the annual submission of FRS Forms 1 and 2. The only time a Balancing Authority should exclude an event is if its tie-line data or its Frequency data is corrupt or its EMS was unavailable. FRS Form 2 has instructions on how to correct the BA's data if the given event is internal to the BA or if other authorized adjustments are used.

Assuming data entry is correct FRS Form 1 will automatically calculate the Balancing Authority's FRM for the past 12 months as the median of the SEFRD values. A Balancing Authority electing to report as an FRSG or a provider of Overlap Regulation Service will provide an FRS Form 1 for the aggregate of its participants.

To allow Balancing authorities to plan its operations, events with a "Point C" that cause the Interconnection Frequency to be lower than that shown in Table 1 above (for example, an event in the Eastern Interconnection that causes the Interconnection Frequency to go to 59.4 Hz) or higher than an equal change in frequency going above 60 Hz may be included in the list of events for that interconnection. However, the calculation of the BA response to such an event will be adjusted to show a frequency change only to the Target Minimum Frequency shown in Table 1 above (in the previous example this adjustment would cause Frequency to be shown as 59.5 Hz rather than 59.4 HZ) or a high frequency amount of an equal quantity. Should such an event happen, the ERO will provide additional guidance.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that contains the sum of each participant's individual event performance.

Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities

Described below is the timeline for the exchange of information between the ERO and Balancing Authorities (BA) to:

- Facilitate the assignment of BA Frequency Response Obligations (FRO)
- Calculate BA Frequency Response Measures (FRM)
- Determine BA Frequency Bias Settings (FBS)

Target Business Date	Activity
~~April 30~~March 1	Form 1 is posted by ~~The~~ the ERO* with all selected events for the operating year for BA usage~~reviews candidate frequency events and selects frequency events for the first quarter (December to February)~~.
April 1	BAs and FRSGs complete their frequency response forms for all four quarters, including the BAs' FBS calculations, returning the results to the ERO.
May 1	The ERO validates FBS values, computes the sum of all FBS values for each Interconnection.
~~May 10~~	~~Form1 is posted with selected events from the first quarter for BA usage by the ERO.~~
May 15	The BAs not required to file FERC Form 714 receive a request to provide load and generation data as described in the ***Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard***** to support FRO assignments and determining minimum FBS for the upcoming year. Data to be provided by July 15.~~The BAs receive a request to provide load and generation data as described in Attachment A to support FRO assignments and determining minimum FBS for BAs.~~
June 1	The BA implements any changes to their FBS.
November 1	The ERO assigns FRO values and Minimum FBS for the upcoming year to the BAs.

* If 4th quarter posting of Form 1s is delayed, the ERO may adjust the other timelines in this table by a similar amount.

** Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

Rationale

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

Rationale for R1:
Text, text, text

Rationale for R2:
Text, text, text

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Proposed Resource Loss Protection Criteria

Background and Current Methodologies

The Resource Loss Protection Criteria (RLPC) is the respective Interconnection design resource loss in MW which is used to determine the Interconnection Frequency Response Obligation (IFRO).
An “N-2 Event” is defined as a single initiating event that leads to multiple (two or more) electrical facilities being removed from service. Examples of this are breaker failure events, bus faults, or double circuit tower outages.

Previously, the RLPC has been calculated from the largest N-2 event identified in each Interconnection, except for the Eastern Interconnection. In the Eastern Interconnection, the RLPC has been calculated using the largest single event in the previous ten years.

The RLPC value should be set for each Interconnection such that the underfrequency load shedding safety net is not activated for the largest N-2 Event. Previous BAL-003 IFRO methodology determined that the largest N-2 Event should not precipitate an underfrequency load shedding event. Ideally, the RLPC value should always equal or exceed the largest N-2 Event. If the RLPC is set to a larger value than the largest N-2 Event, the probability of an underfrequency load shedding event decreases. If the RLPC value is set to a value less than the largest N-2 Event, the probability of an underfrequency load shedding event increases. A quantitative approach to selecting the RLPC can be implemented that minimizes the need for detailed system analysis to be performed annually.

Currently, each Balancing Authority (BA) or Reserve Sharing Group (RSG) determines its Most Severe Single Contingency (MSSC) with respect to resource loss as required by BAL-002-2(i), Requirement R2. The MSSC calculation is done in Real-time operations based on actual system configuration.

Relevant Definitions

For convenience, the definitions of the following terms defined in the Glossary of Terms used in NERC Reliability Standards are provided below. Where a conflict exists between the definition provided here and the definition in the Glossary, the definition in the Glossary shall control.

Most Severe Single Contingency:
The Balancing Contingency Event, due to a single contingency identified using system models maintained within the RSG or a BA’s area that is not part of a RSG, that would result in the greatest loss (measured in Megawatt (MW) of resource output used by the RSG or a BA that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Balancing Contingency Event:
Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less.

A. Sudden loss of generation:
   a. Due to:
      i. unit tripping, or
      ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or
      iii. sudden unplanned outage of transmission Facility.
   b. And that causes an unexpected change to the responsible entity's Area Control Area (ACE).
B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.
C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Interconnection:
A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

Proposal

The Interconnection RLPC is calculated based on a resource loss in accordance with the following process:

- Each BA shall annually determine its two largest MSSC values in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)
- Remedial Action Scheme (RAS) resource loss which is initiated by a single (N-1) contingency event needs to be included in this determination.
- RAS resource loss which is initiated by a multiple (N-2) contingency event needs to be included in this evaluation (RLPC cannot be lower than this value).
- Each BA then submits its two largest resource losses (MSSC1, MSSC2) used to determine its MSSC for a normal (N-0) system configuration using its FRS Form 1. The data is to include:
  - Initiating event, and
  - Megawatt (MW) loss.
- FRS Form 1 data is compiled by NERC for each Interconnection.

- For each Interconnection, the two largest single contingency (N-1) MSSC values are summed to become the Interconnection RLPC.
- If N-2 RAS resource loss for the Interconnection exceeds the RLPC calculated above, then the N-2 RAS resource loss becomes the Interconnection RLPC.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.

For a hypothetical four-BA Interconnection, Plant 1, in BA1, has two generators rated at 1200 MW each. Plant 2, in BA2 has a generator rated at 1400 MW. BA2's next largest contingency is 1000 MW. The two largest resource losses for BA3 and BA4 are listed below.

BA1	MSSC1 = 1200 MW	MSSC2 = 1200 MW	Both MSSCs at Plant 1
BA2	MSSC1 = 1400 MW	MSSC2 = 1000 MW	Electrically separate MSSCs
BA3	MSSC1 = 1000 MW	MSSC2 = 800 MW	Electrically separate MSSCs
BA4	MSSC1 = 1500 MW (DC TIE)	MSSC2 = 500 MW	Electrically separate MSSCs

The ERO would apply the RLPC selection methodology described above to determine the RLPC for the Interconnection. Using this methodology, results in the following:

Interconnection MSSC1 = 1500 MW	Largest MSSC of the four BA's
Interconnection MSSC2 = 1400 MW	Largest remaining MSSC of the four BA's
Interconnection RLPC = 2900 MW	Summation of two largest resource losses
Interconnection Largest N-2 event	2400 MW at BA1's Plant 1

If an N-2 Event was applied, the RLPC for the Interconnection would be 2400 MW. The summation of MSSCs will exceed, but never fall short of, the N-2 Event scenario.

In order to evaluate RAS resource loss, single (N-1) and multiple (N-2) contingency events should be evaluated. Hypothetically, in an Interconnection:

BA1 RAS = 2850 MW N-2 RAS event
BA1 MSSC1 = 1150 MW
BA1 MSSC2 = 800 MW
BA2 MSSC1 = 1380 MW
BA2 MSSC2 = 1380 MW
BA3 RAS = 1000 MW N-1 RAS event
BA3 MSSC1 = 800 MW
BA3 MSSC2 = 700 MW

In this case, the summation of the two largest MSSCs are 2760 MW. However, the N-2 RAS event results in an RAS resource loss of 2850 MW. In this case, the N-2 event exceeds the summation of the two largest single contingency events. Therefore, the RLPC is the N-2 RAS event, or 2850 MW.

North American Interconnection RPLC Values

Based on initial review, the numbers below are believed to be representative of the RLPC for each Interconnection.

<u>Eastern Interconnection:</u>
Present RLPC = 4500 MW Load Credit = 0 MW
MSSC1 = 1732 MW
MSSC2 = 1477 MW
Proposed RLPC = 3209 MW

<u>Western Interconnection:</u>
Present RLPC = 2626 MW Load Credit = 120 MW
MSSC1 = 1505 MW
MSSC2 = 1344 MW
N-2 RAS = 2850 MW
Proposed RLPC = 2850 MW

<u>ERCOT:</u>
Present RLPC = 2750 MW Load Credit = 1209 MW
MSSC1 = 1375 MW
MSSC2 = 1375 MW
Proposed RLPC = 2750 MW

<u>Quebec Interconnection:</u>
Present RLPC = 1700 MW Load Credit = 0 MW
MSSC1 = 1000 MW
MSSC2 = 1000 MW
Proposed RLPC = 2000 MW

SDT Comments:

Background and Explanation (*Not part of the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard document*)

The objectives of the additions to the BAL-003 process document are to:

- Provide a supportable process to address the intent of the B-C ratio and the analysis report
- Streamline the administrative support behind BAL-003, possible examples include
    - Reduce time pressure in getting IFROs and Bias values out
    - Only generate a full new analysis report to determine IFRO when triggered by a decline in performance from base year, otherwise a summary report could be developed and reference the last full report.
- Technically defensible replacement for the 4500 MW basis for the East as well as an on-off ramp for new credible contingencies in any Interconnection.
- While encouraging improvement, preserve reliability at the level when the standard was adopted
- Allow learning and minor changes to administrative processes without opening the standard
    - Characteristics of response may change (fewer events under current selection process if performance improves)
    - Forms improvement
- State of Reliability Report indicators to track reliability
    - Rate of Change of Frequency (RoCoF)/GW loss
    - Normalized M-4
        - Regression analyzed to correct for starting frequency and resource loss size
        - Expressed as Beta per GW loss

Below is an example of how the IFROs could be posted along with other balancing parameters.

Measure	East	West	Texas	Quebec	Notes
Epsilon 1	18mHz	22.8mHz	30mHz	21mHz	Parameter that sets CPS1 and BAAL
Balancing Authority ACE Limit	-700%	-700%	-700%	-700%	BAL-001-2 R2
Reportable Balancing Contingency Event	900MW	400MW	800MW	500MW	NERC Glossary
Interconnection Frequency Response Obligation (2019)	-1002	-840	-286	-179	(MW/0.1Hz)
Interconnection Frequency Response Obligation (2020)	-1120	-840	-286	-179	(MW/0.1Hz)

This procedure outlines the Electric Reliability Organization (ERO) process for supporting the Frequency Response Standard (FRS). A Procedure revision request may be submitted to the ERO for consideration. The revision request must provide a technical justification for the suggested modification. The ERO shall post the suggested modification for a 45-day formal comment period and discuss the revision request in a public meeting. The ERO will make a recommendation to the NERC BOT, which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to this Procedure shall be filed with FERC for informational purposes.

Event Selection Process

Event Selection Objectives

The goals of this procedure are to outline a transparent, repeatable process to annually identify a list of frequency events to be used by Balancing Authorities (BA) to calculate their Frequency Response to determine:

- Whether the BA met its Frequency Response Obligation, and
- An appropriate fixed Bias Setting.

Event Selection Criteria

1. The ERO will use the following criteria to select FRS frequency excursion events for analysis. The events that best fit the criteria will be used to support the FRS. The evaluation period for performing the annual Frequency Bias Setting and the Frequency Response Measure (FRM) calculation is December 1 of the prior year through November 30 of the current year.
2. The ERO will identify 20 to 35 frequency excursion events in each Interconnection for calculating the Frequency Bias Setting and the FRM. If the ERO cannot identify 20 frequency excursion events in a 12 month evaluation period satisfying the criteria below, then similar acceptable events from the subsequent year's evaluation period will be included with the data set by the ERO for determining FRS compliance. This is described later.
3. The ERO will use three criteria to determine if an acceptable frequency excursion event for the FRM has occurred:
    a. The change in frequency as defined by the difference from the A Value to Point C and the arrested frequency Point C exceeds the excursion threshold values specified for the Interconnection in Table 1 below.
        i. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline.
        ii. Point C is the arrested value of frequency observed within 12 seconds following the start of the excursion.

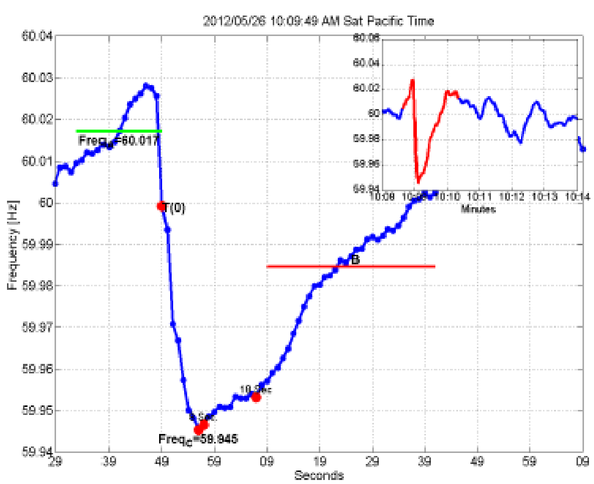
Interconnection	A Value to Pt C	Point C (Low)	Point C (High)
East	0.04Hz	< 59.96	> 60.04
West	0.07Hz	< 59.95	> 60.05
ERCOT	0.15Hz	< 59.90	> 60.10
HQ	0.30Hz	< 59.85	> 60.15

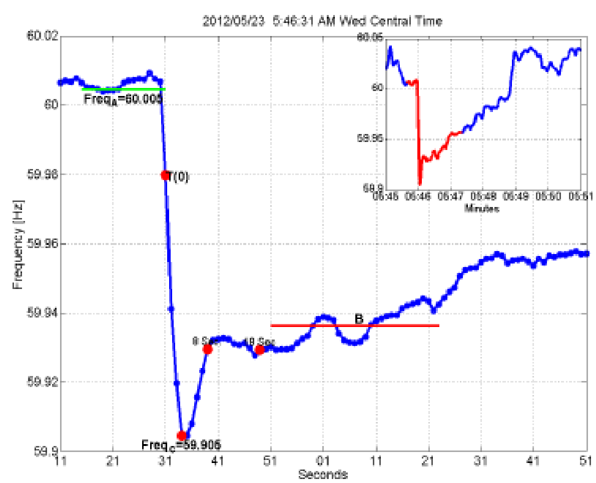
Table 1: Interconnection Frequency Excursion Threshold Values

b. The time from the start of the rapid change in frequency until the point at which Frequency has stabilized within a narrow range should be less than 18 seconds.

c. If any data point in the B Value average recovers to the A Value, the event will not be included.

4. Pre-disturbance frequency should be relatively steady and near 60.000 Hz for the A Value. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline. For example, given the choice of the two events below, the one on the right is preferred as the pre-disturbance frequency is stable and also closer to 60 Hz.





5. Excursions that include 2 or more events that do not stabilize within 18 seconds will not be considered.

6. Frequency excursion events occurring during periods:

   (i) when large interchange schedule ramping or load change is happening, or

   (ii) *w*ithin 5 minutes of the top of the hour,

   will be excluded from consideration if other acceptable frequency excursion events from the same quarter are available.

7. The ERO will select the largest (A Value to Point C) 2 or 3 frequency excursion *e*vents occurring each month. If there are not 2 frequency excursion events satisfying the selection criteria in a month, then other frequency excursion events should be picked in the following sequence:
    a. From the same event quarter of the year.
    b. From an adjacent month.
    c. From a similar load season in the year (shoulder vs. summer/winter)
    d. The largest unused event.

As noted earlier, if a total of 20 events are not available in an evaluation year, then similar acceptable events from the next year's evaluation period will be included with the data set by the ERO for determining Frequency Response Obligation (FRO) compliance. The first year's small set of data will be reported and used for Bias Setting purposes, but compliance evaluation on the FRO will be done using a 24 month data set.

To assist Balancing Authority preparation for complying with this standard, the ERO will provide quarterly posting of candidate frequency excursion events for the current year FRM calculation. The ERO will post the final list of frequency excursion events used for standard compliance as specified in Attachment A of BAL-003-1. The following is a general description of the process that the ERO will use to ensure that BAs can evaluate events during the year in order to monitor their performance throughout the year.

Monthly

Candidate events will be initially screened by the "Frequency Event Detection Methodology" shown on the following link located on the NERC Resources Subcommittee area of the NERC website: http://www.nerc.com/docs/oc/rs/Frequency_Event_Detection_Methodology_and_Criteria_Oct_2011.pdf. Each month's list will be posted by the end of the following month on the NERC website, http://www.nerc.com/filez/rs.html and listed under "Candidate Frequency Events".

Quarterly

The monthly event lists will be reviewed quarterly, with the quarters defined as:

- December through February
- March through May
- June through August
- September through November

Based on criteria established in the "*Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard",* events will be selected to populate the FRS Form 1 for each Interconnection.

The Form 1's will be posted on the NERC website, in the Resources Subcommittee area under the title "Frequency Response Standard Resources". Updated Form 1's will be posted at the end of each quarter listed above after a review by the NERC RS' Frequency Working Group. While the events on this list are expected to be final, as outlined in the selection criteria, additional events may be considered, if the number of events throughout the year do not create a list of at least 20 events. It is intended that this quarterly posting of updates to the FRS Form 1 would allow BAs to evaluate the events throughout the year, lessening the burden when the yearly posting is made.

Annually

The final FRS Form 1 for each Interconnection, which would contain the events from all four quarters listed above, will be posted as specified in Attachment A. Each Balancing Authority reports its previous year's Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO as specified in Attachment A using the final FRS Form 1. The ERO will check for errors and use the FRS Form 1 data to calculate CPS limits and FROs for the upcoming year.

Once the data listed above is fully reviewed, the ERO may adjust the implementation specified in Attachment A for changing the Frequency Bias Settings and CPS limits. This allows flexibility in when each BA implements its settings.

Process for Adjusting Interconnection Minimum Frequency Bias Setting

This procedure outlines the process the ERO is to use for modifying minimum Frequency Bias Settings to better meet reliability needs. The ERO will adjust the Frequency Bias Setting minimum in accordance with this procedure.

The ERO will post the minimum Frequency Bias Setting values on the ERO website along with other balancing standard limits.

Under BAL-003-1, the minimum Frequency Bias Settings will be moved toward the natural Frequency Response in each interconnection. In the first year, the minimum Frequency Bias Setting for each interconnection is shown in Table 2 below. Each Interconnection Minimum Frequency Bias Setting is based on the sum of the non-coincident peak loads for each BA from the currently available FERC 714 Report or equivalent. This non-coincident peak load sum is multiplied by the percentage shown in Table 2 to get the Interconnection Minimum Frequency Bias Setting. The Interconnection Minimum Frequency Bias Setting is allocated among the BAs on an interconnection using the same allocation method as is used for the allocation of the Frequency Response Obligation (FRO).

Interconnection	Interconnection Minimum Frequency Bias Setting (in MW/0.1Hz)
Eastern	0.9% of non-coincident peak load
Western	0.9% of non-coincident peak load
ERCOT*	N/A
HQ*	N/A

Table 2. Frequency Bias Setting Minimums

*The minimum Frequency Bias Setting requirement does not apply to a Balancing Authority that is the only Balancing Authority in its Interconnection. These Balancing Authorities are solely responsible for providing reliable frequency control of their Interconnection. These Balancing Authorities are responsible for converting frequency error into a megawatt error to provide reliable frequency control, and the imposition of a minimum bias setting greater than the magnitude the Frequency Response Obligation may have the potential to cause control system hunting, and instability in the extreme.

The ERO, in coordination with the regions of each interconnection, will annually review Frequency Bias Setting data submitted by BAs. 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 peak load (expressed in MW/0.1Hz), the minimum Frequency Bias Setting for BAs within that Interconnection may be reduced (in absolute value) in the subsequent years FRS Form 1 based on the technical evaluation and consultation with the regions affected by 0.1 percentage point of peak load (expressed in MW/0.1Hz) to better match that Frequency Bias Setting and natural Frequency Response.

The ERO, in coordination with the regions of each Interconnection, will monitor the impact of the reduction of minimum frequency bias settings, if any, on frequency performance, control performance, and system reliability. If unexpected and undesirable impacts such as, but not limited to, sluggish post-contingency restoration of frequency to schedule or control performance problems occur, then the prior reduction in the minimum frequency bias settings may be reversed, and/or the prospective reduction based on the criterion stated above may not be implemented.

Interconnection Frequency Response Obligation (IFRO)

The default IFRO listed in Table 1 is based on the Resource Loss Protection Criteria (RLPC), which is the largest category C (N-2) event identified except for the Eastern Interconnection, which uses the largest event in the last 10 years. A maximum delta frequency (MDF) is calculated by adjusting a starting frequency for each Interconnection by the following:

- Prevailing UFLS first step
- CC_{Adj} which is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data
- CB_R which is the statistically determined ratio of the Point C to Value B
- BC'_{Adj} which is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.

The IFRO for each Interconnection in Table 1 is then calculated by dividing the RLPC MWs by 10 times the MDF. In the Eastern Interconnection there is an additional adjustment (BC'_{Adj}) for the event nadir being below the Value B due to primary frequency response withdrawal. This IFRO includes uncertainty adjustments at a 95 % confidence level. Detailed descriptions of the calculations used in Table 1 below are defined in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.

SDT Comments:

Assuming the industry agrees, this language will be moved to the *Procedure Document*, as it will no longer exist in Attachment A of BAL-003-2. The drafting team recommends removing these procedural steps from Attachment A as they are subject to engineering studies and modifications that can be revised outside of the standards development process.

NOTE: Although the language would no longer be included in the standard under the proposed revisions, this calculation process would remain subject to stakeholder comment on any revisions, and it would remain subject to Board approval/adoption and would be filed with FERC for informational purposes.

The process to modify this document is defined in the first paragraph of this document and states, *"This procedure outlines the Electric Reliability Organization (ERO) process for supporting the Frequency Response Standard (FRS). A Procedure revision request may be submitted to the ERO for consideration. The revision request must provide a technical justification for the suggested modification. The ERO shall post the suggested modification for a 45-day formal comment period and discuss the revision request in a public meeting. The ERO will make a recommendation to the NERC BOT, which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to this Procedure shall be filed with FERC for informational purposes."* The process to modify this document continues in concert with the *Rules of Procedure.*

The information shown here would be modified under the standards drafting team's proposals in the other posted documents in this informal posting. When feedback is received from industry, the standards drafting team will evaluate and modify this section based on comments received.

Interconnection	**Eastern**	**Western**	**ERCOT**	**HQ**	Units
Starting Frequency (F_{Start})	**59.974**	**59.976**	**59.963**	**59.972**	Hz
Prevailing UFLS First Step	**59.5***	**59.5**	**59.3**	**58.5**	Hz
Base Delta Frequency (DF_{Base})	**0.474**	**0.476**	**0.663**	**1.472**	Hz
CC_{ADJ}	**0.007**	**0.004**	**0.012**	**N/A**	Hz
Delta Frequency (DF_{CC})	**0.467**	**0.472**	**0.651**	**1.472**	Hz
CB_R	**1.000**	**1.625**	**1.377**	**1.550**	
Delta Frequency (DF_{CBR})	**0.467**	**0.291**	**0.473**	**0.949**	Hz
BC'_{ADJ}	**0.018**	**N/A**	**N/A**	**N/A**	Hz
Max. Delta Frequency (MDF)	**0.449**	**0.291**	**0.473**	**0.949**	
Resource Contingency Criteria (RCC)	**4,500**	**2,740**	**2,750**	**1,700**	MW
Credit for Load Resources (CLR)		**300**	**1,400****		MW
IFRO	**-1,002**	**-840**	**-286**	**-179**	MW/0.1 Hz

Table 1: Interconnection Frequency Response Obligations

**The Eastern Interconnection UFLS set point listed is a compromise value set midway between the stable frequency minimum established in PRC-006-1 (59.3 Hz) and the local protection UFLS setting of 59.7 Hz used in Florida and Manitoba.*

***In the Base Obligation measure for ERCOT, 1400 MW (Load Resources triggered by Under Frequency Relays at 59.70 Hz) was reduced from its Resource Contingency Criteria level of 2750 MW to get 239 MW/0.1 Hz. This was reduced to accurately account for designed response from Load Resources within 30 cycles.*

An Interconnection may propose alternate IFRO protection criteria to the ERO by submitting a SAR with supporting technical documentation.

Balancing Authority Frequency Response Obligation (FRO) and Frequency Bias Setting

The ERO will manage the administrative procedure for annually assigning an FRO and implementation of the Frequency Bias Setting for each Balancing Authority. The annual timeline for all activities described in this section are shown below.

For a multiple Balancing Authority interconnection, the Interconnection Frequency Response Obligation shown in Table 1 is allocated based on the Balancing Authority annual load and annual generation. The FRO allocation will be based on the following method:

$$\mathrm{FRO_{BA}} = \mathrm{IFRO} \quad \times \frac{\text{Annual Gen}_{\text{BA}} + \text{Annual Load}_{\text{BA}}}{\text{Annual Gen}_{\text{Int}} + \text{Annual Load}_{\text{Int}}}$$

Where:

- Annual Gen_{BA} is the total annual "Output of Generating Plants" within the Balancing Authority Area (BAA), on FERC Form 714, column c of Part II - Schedule 3.
- Annual Load_{BA} is total annual Load within the BAA, on FERC Form 714, column e of Part II - Schedule 3.
- Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that interconnection.
- Annual Load_{Int} is the sum of all Annual Load_{BA} values reported in that interconnection.

The data used for this calculation is from the most recently filed Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which utilized data from 2011.

Balancing Authorities that are not FERC jurisdictional should use the Form 714 Instructions to assemble and submit equivalent data to the ERO for use in the FRO Allocation process.

Interconnection Frequency Response Obligation Methodology

This procedure outlines the process the ERO is to use for determining the Interconnection Frequency Response Obligation (IFRO).

The following are the formulae that comprise the calculation of the IFROs.

$$DF_{Base} = F_{Start} - UFLS$$

$$DF_{CC} = DF_{Base} - CC_{Adj}$$

$$DF_{CBR} = \frac{DF_{CC}}{CB_R}$$

$$MDF = DF_{CBR} - BC'_{Adj}$$

$$ARCC = RCC - CLR$$

$$IFRO = \frac{ARCC}{10 * MDF}$$

Where:

- DF_{Base} is the base delta frequency.
- F_{Start} is the starting frequency determined by the statistical analysis.
- UFLS is the highest UFLS trip setpoint for the interconnection.
- CC_{Adj} is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data.
- DF_{CC} is the delta frequency adjusted for the differences between 1-second and sub-second Point C observations for frequency events.
- CB_R is the statistically determined ratio of the Point C to Value B.
- DF_{CBR} is the delta frequency adjusted for the ratio of the Point C to Value B.
- BC'_{ADJ} is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.
- MDF is the maximum allowable delta frequency.
- RCC is the resource contingency criteria.
- CLR is the credit for load resources.
- ARCC is the adjusted resource contingency criteria adjusted for the credit for load resources.
- IFRO is the interconnection frequency response obligation.

Adjustments to Interconnection Frequency Response Obligations (IFRO)

Similar to the Control Performance Standard, BAL-003 is intended to be tunable, such that if performance degrades or characteristics of an Interconnection change, the IFRO adapts. Information from NERC's annual State of Reliability Report is used to determine if a detailed analysis is needed or if the IFRO needs to be increased. Information for the base year of BAL-003 is outlined in the table below.

Interconnection	Eastern	Western	ERCOT	HQ
Interconnection Median Beta	2,368.6	1,400.0	752.0	543.8
M-4 Point C	59.956	59.918	59.868	59.487
Resource Loss Protection Criteria (RLPC)	4,500	2,740	2,750	1,700
Credit for Load		300	1,400[1]	
IFRO	-1002	-840	-286	-179

Base Year (2016) Data for BAL-003-1

Supporting Annual Frequency Response Analysis

The ERO will review frequency response performance as part of its annual State of Reliability Report analysis. If Operating Year Beta remains above the base year performance, no additional review is necessary. If Operating Year Beta for an Interconnection drops below the BAL-003 base year (currently 2016), a more detailed assessment will be performed to determine if changes are needed to the IFRO. Due to expected variation in sampling and performance, as long as performance remains within 10% of base year performance, no changes in FRO are needed.

If a detailed frequency response analysis is performed, it will be posted on the ERO website.

Changes in Resource Loss Protection Criteria (RLPC)

The default RLPC for an Interconnection will be the sum of the two Most Severe Single Contingencies (MSSC) within the Interconnection. The ERO will annually verify the two largest resources in each Interconnection. If a new RLPC is identified for an Interconnection, there will be a proportional change in IFRO. For example, if a network change in WECC resulted in a 3000 MW RLPC, the new obligation becomes:

[1] The Base Obligation measure for ERCOT, 1400 MW (Load Resources triggered by Under Frequency Relays at 59.70 Hz) was reduced from its Resource Loss Protection Criteria level of 2750 MW to get 239 MW/0.1 Hz. This was reduced to accurately account for designed response from Load Resources within 30 cycles

$$-840 \times (3000/2740) = -920 \text{ MW/0.1Hz}$$

If the change is a reduction in IFRO greater than 10%, the change will be implemented over multiple years. The ERO may pause and reassess a multi-year drop in IFRO if the Interconnection's performance indicators show a statistically significant decline or an event occurs that is larger than the RLPC. The ERO will determine future steps based on analysis.

Credit for Load

Some Interconnections have contractually obligated load that trips at a setpoint above the first step of UFLS. The ERO will annually review changes in the contractual obligation amount and will adjust the credit as appropriate.

As part of its annual analysis, the ERO will confirm whether there has been a material change in the amount of high set interruptible load. Changes in credit for load are not needed if the amount of contributing load has not changed by more than 5%.

Decline in Point C

If the average M-4 Point C in the State of Reliability Report declines below the base year, ERO will as part of its annual analysis determine whether the decline in performance is due to a decline in frequency response or due to other factors (e.g. balancing events not associated generation trips, decline in inertia, increased ramping obligations).

If the review shows the decline in Point C is due to other factors, the issue will be referred to the appropriate stakeholder committee(s).

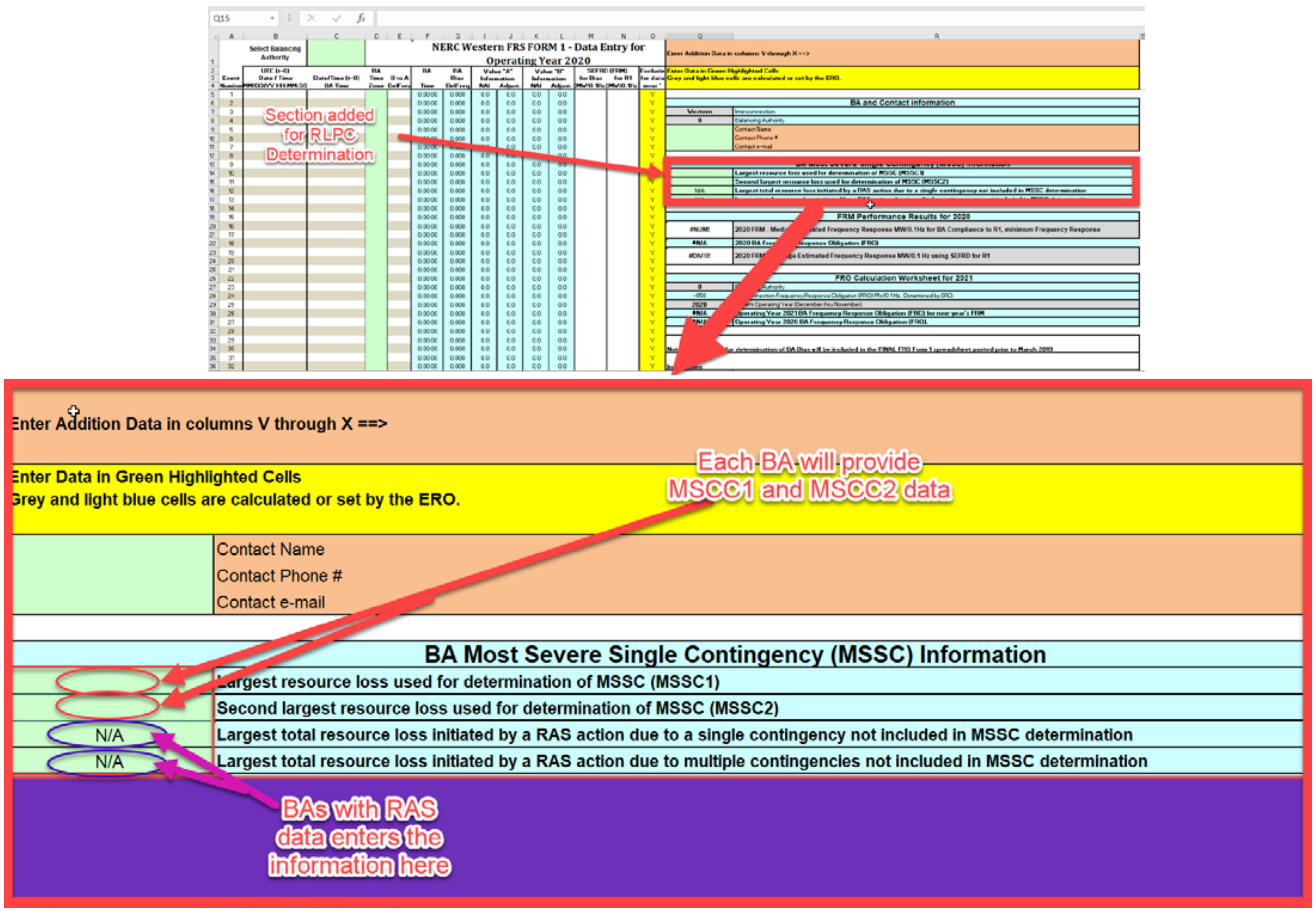
If the review shows the decline in Point C is likely due to a decline in Frequency Response, the ERO will determine if the IFRO needs adjustment.

Posting and Communicating IFRO Changes

While unofficial, NERC will notify Balancing Authorities if it appears there may be IFRO increases in an Interconnection when it provides Balancing Authorities the final FRS Forms for the year. Once analysis is complete, NERC will post current and any upcoming changes in IFRO on its website and provide official notice to Balancing Authorities at the same time as Bias Setting notifications are transmitted.

Modification to *FRS Form 1*

For determination of Resource Loss Protection Criteria (RLPC), each Balancing Authority (BA) will provide data for the determination of the RLPC. In addition to the current practice of providing their frequency response sampling for all four quarters and their Frequency Bias Setting (FBS) calculation, each BA shall provide requested information regarding determination of Most Severe Single Contingencies (MSCC) and resource loss due to Remedial Action Scheme (RAS) actions. To facilitate the collection of data, the *FRS Form 1* has been modified with the addition of the following field:



Unofficial Comment Form

Project 2017-01 Modifications to BAL-003-1.1

Do not use this form for submitting comments. Use the electronic form to submit informal comments on the **Project 2017-01 Modifications to BAL-003-1.1** project. The electronic form must be submitted by **8 p.m. Eastern, Thursday, September 20, 2018**.

Documents and information about this project are available on the project page. If you have questions, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

Background

Project 2017-01 Modifications to BAL-003-1.1
The purpose of this project is to review the issues identified in Phase I of the SAR and make corresponding modifications to BAL-003-1.1, as necessary.

Standard affected: BAL-003-1.1
The supporting documents for BAL-003-1.1 were developed using engineering judgment on the data collection and process needed to determine the Interconnection Frequency Response Obligation (IFRO), as well as the processing of raw data to determine compliance. Now that the Reliability Standard is in place and the data is available for analyses, minor errors in assumptions, as well as process inefficiencies have been identified. It was anticipated that as Frequency Response improves, the approaches embedded in the Reliability Standard for annual samples may need to be modified. In addition to fixing the inconsistencies identified in the Frequency Response Annual Analysis Report (FRAA), the drafting team may separate the administrative and procedural items and reassign them to an alternative process, subject to Electric Reliability Organization (ERO) and North American Electric Reliability Corporation (NERC) Operating Committee approval.

This informal comment period is seeking inputs into the standard drafting team's (SDT) proposed Phase I modifications to BAL-003-1.1:

- Replacing resource contingency criteria (RCC) by proposing a new methodology for determining the Resource Loss Protection Criteria (RLPC) that is consistent across all Interconnections, and is designed to maintain reliability for the respective Interconnections;
- An IFRO methodology that makes changes only when technically justified;
- Limiting the IFRO changes by no more than 10 percent annually and implementing percentage of change over the time period necessary to achieve the appropriate IFRO levels; and
- Move items not related to entity compliance from BAL-003-1.1, Attachment A to the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document.

Please provide your responses to the questions listed below along with any detailed comments.

Questions

1. The SDT is proposing replacing RCC by proposing a new methodology for determining the RLPC that is consistent across all Interconnections, and is designed to maintain reliability for the respective Interconnections. This methodology is described in the *Resource Loss Protection Criteria* document. Is this methodology appropriate for determination of the event that each Interconnection is protecting against? If not, please provide specific language on the proposed revision.

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with using the two Most Severe Single Contingencies (MSSCs) in each Interconnection as the basis for an Interconnection's IFRO? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

   ☐ Yes
   ☐ No

   Comments:

3. The standard drafting team is proposing an IFRO methodology that makes changes only when technically justified. This methodology should maintain a stable IFRO rather than implementing immaterial modifications. Do you agree with keeping IFROs stable over time, similar to CPS1, unless Interconnection Frequency Response significantly declines? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

   ☐ Yes
   ☐ No

   Comments:

4. The IFRO methodology proposed by the drafting team separates several variables from the annual modification of the IFRO, including the C to B ratio and delta frequency, and simplifies the calculation. These variables are being reviewed as part of the analysis process that will occur outside of the standard. Do you agree with the separation of the variables from the annual

calculation? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

☐ Yes
☐ No

Comments:

5. With the modification to the RLPC and IFRO methodologies, the Eastern Interconnection IFRO will experience an approximate 28 percent decrease, and Hydro Quebec will experience an approximate 17 percent increase. The standard drafting team recommends limiting the IFRO changes by no more than 10 percent annually and implementing percentage of change over the time period necessary to achieve the appropriate IFRO levels. Once the transition is complete, modifications to IFRO would not be limited. Do you agree with this staged implementation of the methodology?

   ☐ Yes
   ☐ No

   Comments:

6. The drafting team is proposing to move items not related to entity compliance from BAL-003-1.1, Attachment A to the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document. The SAR recommended such changes to Attachment A. Do you agree that the changes to these documents address the SAR recommendations?

   ☐ Yes
   ☐ No

   Comments:

7. Please provide any additional comments for the SDT to consider that you have not already provided on the Phase I modifications to BAL-003-1.1.

   Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2017-01 Modifications to BAL-003-1.1

Informal Comment Period Open through September 20, 2018

Now Available

A 15-day informal comment period for Project 2017-01 Modifications to BAL-003-1.1, is open through **8 p.m. Eastern, Thursday, September 20, 2018**.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience issues navigating the SBS, contact Linda Jenkins. An unofficial Word version of the comment form is posted on the project page.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The drafting team will review all responses received during the comment period and determine the next steps of the project.

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

North American Electric Reliability Corporation
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Atlanta, GA 30326
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Comment Report

Project Name: 2017-01 Modifications to BAL-003-1.1 | SAR

Comment Period Start Date: 9/6/2018

Comment Period End Date: 9/20/2018

Associated Ballots:

There were 18 sets of responses, including comments from approximately 78 different people from approximately 56 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The SDT is proposing replacing RCC by proposing a new methodology for determining the RLPC that is consistent across all Interconnections, and is designed to maintain reliability for the respective Interconnections. This methodology is described in the *Resource Loss Protection Criteria* document. Is this methodology appropriate for determination of the event that each Interconnection is protecting against? If not, please provide specific language on the proposed revision.

2. Do you agree with using the two Most Severe Single Contingencies (MSSCs) in each Interconnection as the basis for an Interconnection's IFRO? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

3. The standard drafting team is proposing an IFRO methodology that makes changes only when technically justified. This methodology should maintain a stable IFRO rather than implementing immaterial modifications. Do you agree with keeping IFROs stable over time, similar to CPS1, unless Interconnection Frequency Response significantly declines? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

4. The IFRO methodology proposed by the drafting team separates several variables from the annual modification of the IFRO, including the C to B ratio and delta frequency, and simplifies the calculation. These variables are being reviewed as part of the analysis process that will occur outside of the standard. Do you agree with the separation of the variables from the annual calculation? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

5. With the modification to the RLPC and IFRO methodologies, the Eastern Interconnection IFRO will experience an approximate 28 percent decrease, and Hydro Quebec will experience an approximate 17 percent increase. The standard drafting team recommends limiting the IFRO changes by no more than 10 percent annually and implementing percentage of change over the time period necessary to achieve the appropriate IFRO levels. Once the transition is complete, modifications to IFRO would not be limited. Do you agree with this staged implementation of the methodology?

6. The drafting team is proposing to move items not related to entity compliance from BAL-003-1.1, Attachment A to the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document. The SAR recommended such changes to Attachment A. Do you agree that the changes to these documents address the SAR recommendations?

7. Please provide any additional comments for the SDT to consider that you have not already provided on the Phase I modifications to BAL-003-1.1.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
PJM Interconnection, L.L.C.	Albert DiCaprio	2	RF,SERC	ISO Standards Review Committee	Ben Li	IESO	2	NPCC
					Mark Holman	PJM	2	RF
					Kathleen Goodman	ISONE	2	NPCC
					Greg Campoli	NYISO	2	NPCC
					Terry Bilke	MISO	2	RF
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Powert	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
PPL - Louisville Gas and	Devin Shines	3,5,6	RF,SERC	Louisville Gas and Electric	Charles Freibert	PPL - Louisville Gas	3	SERC

Electric Co.				Company and Kentucky Utilities Company		and Electric Co.		
					JULIE HOSTRANDER	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
Southwest Power Pool, Inc. (RTO)	Jim Williams	2	MRO,SERC	SPP Standards Review Group	Jim Williams	SPP	2	MRO
					Shannon Mickens	SPP	2	MRO
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC

Alan Adamson	New York State Reliability Council	7	NPCC
Edward Bedder	Orange & Rockland Utilities	1	NPCC
David Burke	Orange & Rockland Utilities	3	NPCC
Michele Tondalo	UI	1	NPCC
Laura Mcleod	NB Power	1	NPCC
David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
Helen Lainis	IESO	2	NPCC
Michael Schiavone	National Grid	1	NPCC
Michael Jones	National Grid	3	NPCC
Michael Forte	Con Ed - Consolidated Edison	1	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Sean Cavote	PSEG	4	NPCC
Kathleen Goodman	ISO-NE	2	NPCC
Quintin Lee	Eversource Energy	1	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Shivaz Chopra	New York Power Authority	6	NPCC
David Kiguel	Independent	NA - Not Applicable	NPCC

					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC

1. The SDT is proposing replacing RCC by proposing a new methodology for determining the RLPC that is consistent across all Interconnections, and is designed to maintain reliability for the respective Interconnections. This methodology is described in the *Resource Loss Protection Criteria* document. Is this methodology appropriate for determination of the event that each Interconnection is protecting against? If not, please provide specific language on the proposed revision.

Glenn Barry - Los Angeles Department of Water and Power - 1,3,5,6

Answer	No
Document Name	

Comment

The methodology is sound in principle and intent, however the utilization of MSSC may be incorrect. MSSC is a defined term for reserve planning, and if the intent is to look at interconnection resource loss, then using the term MSSC may mislead entities and result in unintended information being submitted and utilized in the IFRO calculation. Perhaps not using MSSC, but defining a different term and providing more clarification and instructions are warranted.

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	No
Document Name	

Comment

Xcel Energy supports the present N-2 Event and also including the N-2 RAS in the methodology. The present N-2 event approach has resulted in reliable operations in the West. Linking reserves to a single credible N-2 event (generation loss or RAS) is reasonable and justifiable. We are not aware of the basis for the Eastern Interconnection IFROs using the largest event in the last 10 years. While the goal RLPC consistent across all Interconnections is commendable, it may not be reasonable to expect each to have the same IFRO basis. If one Interconnection's Frequency Response is declining over several years we would expect their IFRO to be adjusted accordingly.

Likes 0	
Dislikes 0	

Response

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6

Answer	No
Document Name	

Comment	
The goal of consistency is commendable, but use of MSSC may result in unintended consequences over the present method. The term "MSSC" is used for reserve planning, and is associated with specific BAs. Using this term to determine Interconnection resource loss may result in utilizing values that are too small when calculating IFRO. For example, the Interconnection loses all of a joint owned unit, but a BA loses only its portion of the unit. Therefore, the MSSC will understate the size of the loss which may result in calculating an IFRO that is inadequate. Defining a different term, and providing instruction and clarification regarding its determination, is a better approach - presuming the new term(s) is(are) technically based.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	
AEP believes this is a reasonable and transparent methodology to determine the primary variable used to establish an IFRO.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	

Comment	
The proposed RLPC establishes the same basis for all interconnections and eliminates the current higher expectation for the Eastern Interconnection. We struggle with the statement that establishing a minimum generator governor response for an Interconnection is a primary or important tool to protect itself from an N-2 event. For the Eastern Interconnection the proposed N-2 event is a loss of 3209 MW and the current required FRO for the Interconnection is 1015 MW/.1 Hz. The primary protection for a sudden generation loss is established in BAL-002-2(i), if both losses occur with a single BA then the event becomes the second loss. *In the Eastern Interconnection MSSC1 and MSSC2 are both within a single BA. Thus the actual event we are protecting ourselves against is MSSC2, MSSC1 is addressed by the BA's response iaw BAL-002-2(i).* *Are we properly defining the event that this standard is assisting the BAs in protecting themselves against?*	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA is in support of replacing the RLPC so that it is consistent across all interconnections. The method presented in the draft *Resource Loss Protection Criteria* document seems appropriate for determination of the event that each Interconnection should protect against. Specifically, BPA supports the use of either the largest credible and studied (N-2) type contingency that results in a frequency deviation for a known MW loss, or the summation of the two largest MSSCs in an interconnection. While it is not likely that two separate MSSC events would occur at the same time, it seems like a plausible way to derive a number to protect against. The BAL-003 standard should protect against a larger, infrequent event. BPA suggests the document clarify that credible and studied N-2 events are included in the evaluation. The way the *Resource Loss Protection Criteria* document is worded makes it seem like only N-2 RAS events are looked at in the list of N-2 events.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
In the Proposal section of the Proposed RLPC document, it states that each BA will submit their two largest resource losses. It then says that data will include "Initiating event, and Megawatt (MW) loss. But the proposed revised FRS Form 1 only has one empty box for MSSC1 and MSSC2, presumably	

for the MW value. To reduce the potential for confusion, AZPS recommends clarifying the language within the proposal section or the boxes on the FRS Form 1, whichever is the desired result. Additionally, on page 4 of Proposed RLPC document, an incorrect acronym **RPLC** is used in the header.	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT understands the need to address the existing inconsistencies among different interconnections with respect to the current RCC criteria, but does not necessarily agree with the proposed approach.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
We appreciate the new consistent approach applied between all interconnections.	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SERC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with using the two Most Severe Single Contingencies (MSSCs) in each Interconnection as the basis for an Interconnection's IFRO? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT disagrees in principle with the proposed approach of using the two largest units as a credible contingency, primarily because the probability of two units located hundreds of miles apart tripping on a single initiating event is extremely low. This is not a credible risk that should be addressed by the NERC standards. Depending on how the RLPC is determined, if a large Generator or a DC Tie were to be interconnected hundreds of miles away from another large Generator, the proposed RLPC definition would require ERCOT to procure significant additional reserves at great expense in order to protect UFLS against the proposed RLPC.	
Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF	
Answer	No
Document Name	
Comment	
As it is uncertain where the industry will trend in future years in terms of new resource sizing and large resource retirements, there is the possibility that the magnitude of the Most Severe Single Contingencies will get smaller and possibly more will be based upon loss of transmission. Duke Energy suggests that the drafting team consider basing the IFRO on the greater of a fixed percentage of the minimum Interconnection load or the two Most Severe Single Contingencies.	
Likes 0	
Dislikes 0	
Response	

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	No
Document Name	
Comment	

MSSC may result in calculating IFRO that is insufficient to cover actual Interconnection events as previously stated. Joint owned units provide one example of using MSSC and achieving a non-conservative IFRO value. Another example relates to loss of DC ties, where total transfer may be distributed among multiple BAs resulting in MSSCs being smaller than the Interconnection contingency.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
There is no technical justification for using two MSScs as one of the basis for IFRO. We cannot support going to a MSSC approach without strong technical analysis and supporting historical data. One suggestion is that there could be an actual event where two concurrent MSSCs exceed the single N-2 then the MSSC could become the basis for 3 years.	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	
Comment	
MSSC is a defined term, and if the intent is to look at interconnection resource loss, then using the term MSSC may mislead entities and result in unintended information being submitted and utilized in the IFRO calculation. Perhaps not using MSSC, but defining a different term and providing more clarification and instructions are warranted. **Example 1:** **There is a potential gap in reporting JOU/Dynamically scheduled units. LADWP has two JOU that are 900 MW (net) each but only receive 600 MW from each, with the remaining energy sinking in other BAs. It would then be reported as MSSC1 being 600 MW and MSSC2 being 600 MW. In actuality if both units were lost it would be an 1800 MW resource loss to the interconnection, and not the reported 1200 from MSSC 1 and MSSC 2 specified. Since MSSC is a defined term, LADWP would not plan to meet a 900 MW resource loss as MSSC.**	

Example 2:

This example may be unique to the Western Interconnection and PDCI operation. An BA's operational plans might consider their MSSC as their portion of PDCI schedules (since the sink BA is the reserve responsible entity for schedules that traverse PDCI). For example a sink entity may have an MSSC1 of 2300 MW to represent their maximum PDCI schedules, however this would be not be all of the schedule on PDCI, and also this would be included as part of the N-2 RAS action generation resource loss reported by a separate entity. When taking 2300 MW for MSSC1 + 1500 MW for MSSC 2 for another large unit, then the total result would be 3800 MW, larger than the N-2 RAS of 2850 MW. MSSC is a defined term for reserve planning, which can be different than assessing interconnection resource loss.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6

Answer	Yes
Document Name	

Comment

Although AZPS agrees with the proposal for using the two MSSCs for the basis for an Interconnection's IFRO, it does not believe the current proposed collection method for this data will result in what the SDT intends to collect for the following reasons:

Following the definition of MSSC, a Balancing Authority who is in a RSG would not have a discrete MSSC. As the definition states, an MSSC is a Balancing Contingency Event "within the RSG or a BA's area that is not part of a RSG." Therefore those Balancing Authorities inside an RSG would have nothing to report. Similarly, who will be reporting the MSSC for the RSG since RSGs do not fill out Form 1 and those MSSCs are typically the largest MSSCs.

A good illustration of this collection method concern is Palo Verde nuclear generating units. One of these units total output would not be reported by any RSG or BA area that is not part of a RSG as AZPS is part of an RSG, meaning it does not qualify as an entity who has an MSSC. Hence, this MSSC would not be appropriately captured under the current proposal.

Additionally, if a Balancing Authority inside an RSG is made to report a value, the revised form does not contemplate when a BA has a different MSSC depending on the time of year. One reason this can occur is due to Power Purchase Agreements. A BA's MSSC during one half of the year could be their MSSC2 for the second half of the year. Here is an illustration:

BA1 MSSC1 500 MW (January – June)

BA1 MSSC2 300 MW (January – June)

BA1 MSSC1 600 MW Power Purchase Agreement (July – December)

BA1 MSSC2 500 MW (July – December)

In this example, these two resources cannot be combined to serve as both the MSSC1 and MSSC2 for all times of the year. During January – June the 600 MW unit is BA2's MSSC. If BA1 claims the 600 MW unit as their MSSC, it is likely BA2 will claim it as well, resulting in the unit being counted twice. What should BA1's MSSC1 and MSSC2?

For these reasons, AZPS recommends that the SDT review and revise the current proposal regarding the reporting of this information.

Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
While having two MSSC events happen at the same time is not statistically probable, using the combination of the two largest MSSCs gives a method for determining a known MW amount that the interconnection should plan for in the case of an extreme event. If it happens to be larger than already studied N-2 events, then the higher IFRO should increase reliability.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	

AEP believes the proposal leverages existing processes and produces a defendable result.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - SERC,RF, Group Name ISO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SERC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. The standard drafting team is proposing an IFRO methodology that makes changes only when technically justified. This methodology should maintain a stable IFRO rather than implementing immaterial modifications. Do you agree with keeping IFROs stable over time, similar to CPS1, unless Interconnection Frequency Response significantly declines? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.	
Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	
Though AEP agrees in principal with the overall goal, we must reserve final judgement until more specifics are provided to support the reasoning.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
We concur with keeping the IFRO methodology stable similar to CPS. At issue is the determination of a significant decline in Frequency Response – will some metric be established? In addition the technical justification of how a significant decline in Frequency Response indicates a challenge to an Interconnections protection in recovering from a N-2 event isn't well established.	

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

BPA understands that the IFRO is calculated based on a statistically derived starting frequency and CBR ratio. In general, BPA agrees that the IFRO need not change for minute statistical changes. However if there is a change to the RLPC that would raise the obligation, it makes sense that the change to IFRO happens quickly in order to protect against this event. It would be good to clarify the language to say that the IFRO stays the same year to year unless there is a significant change in Interconnection Frequency Response Performance, the RLPC, or statistical inputs to the IFRO.

Likes 0	
Dislikes 0	

Response

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6

Answer	Yes
Document Name	

Comment

GCPD supports an IFRO methodology that makes changes only when technically justified, and keeps IFRO stable year over year. However, if IFRO is inadequate to respond to actual, or probable, events; IFRO should continue to change annually to provide reliable operation. While it is difficult to respond to this question because the interpretation of when "...Interconnection Frequency Response significantly declines" is nebulous, inadequate IFRO may be caused by factors other than a decline in frequency response such as discovering events that demand significantly more IFRO to respond to the size of the loss. (e.g. loss of large amounts of resources related to inverter performance related to distributed energy resources)

Likes 0	
Dislikes 0	

Response

Glenn Barry - Los Angeles Department of Water and Power - 1,3,5,6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SERC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - SERC,RF, Group Name ISO Standards Review Committee	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	
Document Name	
Comment	
Xcel Energy completely agrees that the changes must be technically justifiable. However, we feel any increase in an Interconnection's IFRO should be driven by actual degradation in an Interconnection's Frequency response and not by a technically unjustified change in the basis.	
Likes 0	
Dislikes 0	
Response	

4. The IFRO methodology proposed by the drafting team separates several variables from the annual modification of the IFRO, including the C to B ratio and delta frequency, and simplifies the calculation. These variables are being reviewed as part of the analysis process that will occur outside of the standard. Do you agree with the separation of the variables from the annual calculation? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	No
Document Name	
Comment	
If these values are used to determine compliance or to determine mandated values/limits, they should be part of the standard.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Until phase 2 of this SDT process can occur, BPA does not support changing the core way that IFRO is calculated. In phase 2, the entire methodology of IFRO could be called into question. Until those more thorough discussions happen, it does not make sense to change the IFRO methodology beyond what was suggested for the RLPC. The RLPC should be reviewed annually and IFRO calculated based on the RLPC. Movement towards a new RLPC should be implemented completely, but changes due to small changes in CBR ratio or starting frequency should not require changing the IFRO yearly.	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
These details are an essential part of the standard as they directly impact the determination of a BAs FRM.	
Likes 0	

Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
We cannot support removing these variables (for the MDF calculation in particular) from Attachment A until we see where they will be moved, in terms of new documents, and under what venue this analysis will occur.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
See comments	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
In the **Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard** it states the RLPC for the Eastern Interconnection is "the largest event in the last 10 years." But the **Proposed Resource Loss Protection Criteria** does not provide for this exception. Please clarify which is correct.	
Likes 0	

Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	
AEP believes the current methodology could be improved, but simplification itself should not be the primary goal. Rather, the key to success would be to have a well thought-out and documented process.	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SERC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - SERC,RF, Group Name ISO Standards Review Committee	
Answer	
Document Name	
Comment	
See resposee to Question 7 and also see attached comments	
Likes 0	
Dislikes 0	

Response

5. With the modification to the RLPC and IFRO methodologies, the Eastern Interconnection IFRO will experience an approximate 28 percent decrease, and Hydro Quebec will experience an approximate 17 percent increase. The standard drafting team recommends limiting the IFRO changes by no more than 10 percent annually and implementing percentage of change over the time period necessary to achieve the appropriate IFRO levels. Once the transition is complete, modifications to IFRO would not be limited. Do you agree with this staged implementation of the methodology?

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

There's no justification for establishing a lower FRO for an Interconnection whose MSSC1 and MSSC2 clearly indicate that more FRO is needed to protect that Interconnection from the currently defined event. If during this phase in an event occurs that the Interconnection can't respond to is NERC willing to accept the responsibility for requiring less when clearly more was needed?

Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

BPA thinks that the staged approach makes sense if the IFRO is lowering. If the IFRO is increasing then the change should happen immediately to support reliability.

Likes 0	
Dislikes 0	
Response	

sean erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	

The Purpose as written for BAL-003 is: To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value.

To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.

the question as written would suggest, "*except when the delta is large"*.

If the intent is to limit the decrease in the East as a conservative precaution, then YES, WAPA does agree, **but to allow less than required when the new methodology dictates a need for more violates the purpose of the standard**.

Likes 0	
Dislikes 0	

Response

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6

Answer	No
Document Name	

Comment

The concept of this question is wrong on several levels. First, if the new methodology is technically sound - which remains to be shown - then there is every reason to enforce the new IFRO values at the next annual change because the Eastern Interconnection does not need the present amount for reliable operation, and Hydro Quebec has a reliability risk because it is short.

Next, what is the technical justification for limiting change to 10% rather than 5%, 7%, 15%, etc.? Does it provide 80% of the benefit at 20% of the cost or achieve some other merit that warrants the risk that is accepted by using a value that is recognized as inadequate?

Proposing such a limit calls both the present and proposed methodology into question because one or the other, or perhaps both, must be wrong. Perhaps separate Interconnection methods provide more reliable results, or at least result in less surplus being required by an Interconnection. If Hydro Quebec is reliable today, then there is no need to force them to increase IFRO 17% just to treat all Interconnections the same. Conversely, if they are 17% short, they should correct the deficiency at the next scheduled IFRO change. The real issue is whether the proposed methodology is a better measure to identify necessary IFRO than the old methodology. If so, why?

Likes 0	
Dislikes 0	

Response

Glenn Barry - Los Angeles Department of Water and Power - 1,3,5,6

Answer	Yes
Document Name	

Comment

How was 10% chosen, and is there a basis for that value. It is conservative approach to have staged implementation to large reductions in IFRO. However with IFRO being a reliability measure intended to prevent UFLS what is justification for restricting increases in IFRO greater than 10%?

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	
AEP prefers a gradual change of IFRO in response to real changes in the BPS, and we believe the proposed 10 percent is a reasonable annual limit.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
As part of the eastern interconnection, we agree with the phased-in approach. This is more impactive with the increasing IFRO but fair to apply the phasing-in in both directions.	

Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SERC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	
Document Name	
Comment	
We do not support the 2 MSSC approach and thus have no comment.	
Likes 0	
Dislikes 0	
Response	
Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - SERC,RF, Group Name ISO Standards Review Committee	
Answer	
Document Name	
Comment	
See resposee to Question 7 and also see attached comments	
Likes 0	
Dislikes 0	
Response	

6. The drafting team is proposing to move items not related to entity compliance from BAL-003-1.1, Attachment A to the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document. The SAR recommended such changes to Attachment A. Do you agree that the changes to these documents address the SAR recommendations?

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6

Answer	No
Document Name	

Comment

Requirement 1 requires a BA's FRM to be calculated in accordance with Attachment A, and that its FRM be "...equal to or more negative than its Frequency Response Obligation (FRO)..." Hence, FRO is an obligation and should remain in the standard and subject to the standards drafting process. Keeping the calculations as part of the standard can occur without specifying who is responsible for completing such calculations, though.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

Because the IFRO calculations are the basis for much of the current BAL-003 standard, the IFRO methodology should stay in Attachment A of the standard. Numbers that may change from year to year should move to the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document. However, the methodology and rules for determining and calculating IFRO should stay in the Attachment and not be changed unless it goes through a SAR process.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company

Answer	No
Document Name	

Comment

Requirement R1 requires that a "Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO)….” Since the BA's FRM must be equal to or more negative than its FRO, the FRO is a compliance obligation. Compliance obligations should be included in the language of the Standards and Requirements and be subject to the full Standards Drafting Process.

LG&E/KU recommends that the IFRO and FRO calculations be set forth in Attachment A without reference to who is responsible for the administrative task of completing the calculations. A similar approach can be seen in BAL-001-2 Attachments 1 and 2 where the equations supporting the Requirements in the Standard are set forth. If the calculations are set forth in Attachment A, then the responsibility for the administrative task of completing the calculations can be stated in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

See comments

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6

Answer	Yes
Document Name	

Comment

Although AZPS agrees in concept to moving these items from Attachment A to the **Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard**, it would be helpful if the SDT would move this language to the procedure and amend the procedure in a proper draft form for proper review by industry. This would avoid errors such as:

- The current posted draft version containing references to itself (last sentence of page 8 “Detailed descriptions of the calculations used in Table 1 below are defined in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.”).
- Page 4 under subtitle “Monthly”, the link cited is no longer valid.
- There are new items that are not redlined, which does not allow the reviewer to recognize what are new concepts.

Moving the **Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities** from Attachment A to the **Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard** would be another recommended change since these dates and tasks have changed and have not always been adhered to.

To allow industry to properly review and evaluate the proposed document, we recommend, at a minimum, an accurate clean version be provided and possibly a redlined version if a meaningful approximation can be constructed.

Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Acceptable to move non entity compliance (including non IFRO) to the "Procedure...." document.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	
AEP agrees in principle with the concept. To be acceptable, the “Procedure” would need to have well-defined steps, boundaries to the use of	

engineering judgement, clear roles, clear responsibilities, and oversight.

Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SERC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - SERC,RF, Group Name ISO Standards Review Committee	
Answer	
Document Name	
Comment	
See resposee to Question 7 and also see attached comments	
Likes 0	
Dislikes 0	
Response	

7. Please provide any additional comments for the SDT to consider that you have not already provided on the Phase I modifications to BAL-003-1.1.

Thomas Foltz - AEP - 3,5	
Answer	
Document Name	
Comment	
While we appreciate the drafting team's need for input regarding their efforts, a 14 day turnaround time is not adequate opportunity for industry to provide thoughtful, meaningful feedback on the subject matter.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	
Document Name	
Comment	
The document *Proposed Resource Loss Protection Criteria* states, "The MSSC calculation is done in Real-time operations based on actual system configuration." This statement is not universally accurate and should be removed.	
Likes 0	

response to provide response in less than 30 cycles to arrest frequency decay. Any applicable entity that has a demand response program designed to arrest large frequency deviation that responds before UFLS trigger is eligible for credit. Not assigning the LR credit would cause to IFRO requirement to almost more than double while trying to protect against the same RCC or RLPC.

Likes 0	
Dislikes 0	

Response

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

No response.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	
Document Name	

Comment

We support the changes as they represent a more stream-lined standard.

Likes 0	
Dislikes 0	

Response

Consideration of Comments

Project Name:	2017-01 Modifications to BAL-003-1.1 | SAR
Comment Period Start Date:	9/6/2018
Comment Period End Date:	9/20/2018
Associated Ballots:	

There were 18 sets of responses, including comments from approximately 78 different people from approximately 56 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Senior Director of Engineering and Standards, Howard Gugel (via email) or at (404) 446-9693.

Questions

1. The SDT is proposing replacing RCC by proposing a new methodology for determining the RLPC that is consistent across all Interconnections, and is designed to maintain reliability for the respective Interconnections. This methodology is described in the *Resource Loss Protection Criteria* document. Is this methodology appropriate for determination of the event that each Interconnection is protecting against? If not, please provide specific language on the proposed revision.

2. Do you agree with using the two Most Severe Single Contingencies (MSSCs) in each Interconnection as the basis for an Interconnection's IFRO? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

3. The standard drafting team is proposing an IFRO methodology that makes changes only when technically justified. This methodology should maintain a stable IFRO rather than implementing immaterial modifications. Do you agree with keeping IFROs stable over time, similar to CPS1, unless Interconnection Frequency Response significantly declines? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

4. The IFRO methodology proposed by the drafting team separates several variables from the annual modification of the IFRO, including the C to B ratio and delta frequency, and simplifies the calculation. These variables are being reviewed as part of the analysis process that will occur outside of the standard. Do you agree with the separation of the variables from the annual calculation? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

5. With the modification to the RLPC and IFRO methodologies, the Eastern Interconnection IFRO will experience an approximate 28 percent decrease, and Hydro Quebec will experience an approximate 17 percent increase. The standard drafting team recommends limiting the IFRO changes by no more than 10 percent annually and implementing percentage of change over the time period necessary to achieve the appropriate IFRO levels. Once the transition is complete, modifications to IFRO would not be limited. Do you agree with this staged implementation of the methodology?

6. The drafting team is proposing to move items not related to entity compliance from BAL-003-1.1, Attachment A to the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document. The SAR recommended such changes to Attachment A. Do you agree that the changes to these documents address the SAR recommendations?

7. Please provide any additional comments for the SDT to consider that you have not already provided on the Phase I modifications to BAL-003-1.1.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
PJM Interconnection, L.L.C.	Albert DiCaprio	2	RF,SERC	ISO Standards Review Committee	Ben Li	IESO	2	NPCC
					Mark Holman	PJM	2	RF
					Kathleen Goodman	ISONE	2	NPCC
					Greg Campoli	NYISO	2	NPCC
					Terry Bilke	MISO	2	RF
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casuscelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO

					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
PPL - Louisville Gas and Electric Co.	Devin Shines	3,5,6	RF,SERC	Louisville Gas and Electric Company and Kentucky Utilities Company	Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					JULIE HOSTRANDER	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC

					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
Southwest Power Pool, Inc. (RTO)	Jim Williams	2	MRO,SERC	SPP Standards Review Group	Jim Williams	SPP	2	MRO
					Shannon Mickens	SPP	2	MRO
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC

					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC

					Michael Forte	Con Ed - Consolidated Edison	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Sean Cavote	PSEG	4	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					David Kiguel	Independent	NA - Not Applicable	NPCC
					Silvia Mitchell	NextEra Energy -	6	NPCC

						Florida Power and Light Co.		
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC

1. The SDT is proposing replacing RCC by proposing a new methodology for determining the RLPC that is consistent across all Interconnections, and is designed to maintain reliability for the respective Interconnections. This methodology is described in the *Resource Loss Protection Criteria* document. Is this methodology appropriate for determination of the event that each Interconnection is protecting against? If not, please provide specific language on the proposed revision.

Summary Responses:

The effort of the SDT is to develop a consistent RLPC methodology that is consistent across all Interconnections. The proposed methodology for IFRO will be adjustable per Interconnection if it is determined that an Interconnection's response is declining, while maintaining the consistent approach to the baseline RLPC.

The SDT will evaluate the generator governor response in Phase II of this project. Ultimately, the SDT is defining a methodology that identifies the magnitude needed to protect the reliability of the Interconnection. The RLPC value should always equal or exceed the largest N-2 Event. If the RLPC is set equal to or larger than the largest N-2 Event, the probability of an underfrequency load shedding event stays the same or decreases. The methodology provides an RLPC greater than or equal to the largest N-2 Event for each Interconnection. The SDT will provide detailed explanation as the project develops. Based on comments received, the SDT will be recommending that a decrease to the IFRO will be stepped-in to allow evaluation, and an increase to the IFRO will be implemented in a single step.

Glenn Barry - Los Angeles Department of Water and Power - 1,3,5,6

Answer	No
Document Name	

Comment

The methodology is sound in principle and intent, however the utilization of MSSC may be incorrect. MSSC is a defined term for reserve planning, and if the intent is to look at interconnection resource loss, then using the term MSSC may mislead entities and result in unintended information being submitted and utilized in the IFRO calculation. Perhaps not using MSSC, but defining a different term and providing more clarification and instructions are warranted.

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT understands your concern and will address it during development of the project.	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
Xcel Energy supports the present N-2 Event and also including the N-2 RAS in the methodology. The present N-2 event approach has resulted in reliable operations in the West. Linking reserves to a single credible N-2 event (generation loss or RAS) is reasonable and justifiable. We are not aware of the basis for the Eastern Interconnection IFROs using the largest event in the last 10 years. While the goal RLPC consistent across all Interconnections is commendable, it may not be reasonable to expect each to have the same IFRO basis. If one Interconnection's Frequency Response is declining over several years we would expect their IFRO to be adjusted accordingly.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The effort of the SDT is to develop a consistent RLPC methodology that is consistent across all Interconnections. The proposed methodology for IFRO will be adjustable per Interconnection if it is determined that an Interconnection’s response is declining, while maintaining the consistent approach to the baseline RLPC.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	No
Document Name	
Comment	

The goal of consistency is commendable, but use of MSSC may result in unintended consequences over the present method. The term "MSSC" is used for reserve planning, and is associated with specific BAs. Using this term to determine Interconnection resource loss may result in utilizing values that are too small when calculating IFRO. For example, the Interconnection loses all of a joint owned unit, but a BA loses only its portion of the unit. Therefore, the MSSC will understate the size of the loss which may result in calculating an IFRO that is inadequate. Defining a different term, and providing instruction and clarification regarding its determination, is a better approach - presuming the new term(s) is (are) technically based.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT understands your concern and will address it during development of the project.	
Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	
AEP believes this is a reasonable and transparent methodology to determine the primary variable used to establish an IFRO.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	

Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The proposed RLPC establishes the same basis for all interconnections and eliminates the current higher expectation for the Eastern Interconnection. We struggle with the statement that establishing a minimum generator governor response for an Interconnection is a primary or important tool to protect itself from an N-2 event. For the Eastern Interconnection, the proposed N-2 event is a loss of 3209 MW and the current required FRO for the Interconnection is 1015 MW/.1 Hz. The primary protection for a sudden generation loss is established in BAL-002-2(i), if both losses occur with a single BA then the event becomes the second loss. *In the Eastern Interconnection MSSC1 and MSSC2 are both within a single BA. Thus the actual event we are protecting ourselves against is MSSC2; MSSC1 is addressed by the BA's response iaw BAL-002-2(i).* *Are we properly defining the event that this standard is assisting the BAs in protecting themselves against?*	
Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The SDT will evaluate the generator governor response in Phase II of this project. Ultimately, the SDT is defining a methodology that identifies the magnitude needed to protect the reliability of the Interconnection. The RLPC value should always equal or exceed the largest N-2 Event. If the RLPC is set equal to or larger than the largest N-2 Event, the probability of an underfrequency load shedding event stays the same or decreases. The methodology provides an RLPC greater than or equal to the largest N-2 Event for each Interconnection. The SDT will provide detailed explanation as the project develops. Based on comments received, the SDT will be recommending that a decrease to the IFRO will be stepped-in to allow evaluation and an increase to the IFRO will be implemented in a single step.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA is in support of replacing the RLPC so that it is consistent across all interconnections. The method presented in the draft *Resource Loss Protection Criteria* document seems appropriate for determination of the event that each Interconnection should protect against. Specifically, BPA supports the use of either the largest credible and studied (N-2) type contingency that results in a frequency deviation for a known MW loss, or the summation of the two largest MSSCs in an interconnection. While it is not likely that two separate MSSC events would occur at the same time, it seems like a plausible way to derive a number to protect against. The BAL-003 standard should protect against a larger, infrequent event. BPA suggests the document clarify that credible and studied N-2 events are included in the evaluation. The way the *Resource Loss Protection Criteria* document is worded makes it seem like only N-2 RAS events are looked at in the list of N-2 events.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees and will clarify this issue as the project develops.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	

Answer	Yes
Document Name	
Comment	
In the Proposal section of the Proposed RLPC document, it states that each BA will submit their two largest resource losses. It then says that data will include “Initiating event, and Megawatt (MW) loss. But the proposed revised FRS Form 1 only has one empty box for MSSC1 and MSSC2, presumably for the MW value. To reduce the potential for confusion, AZPS recommends clarifying the language within the proposal section or the boxes on the FRS Form 1, whichever is the desired result. Additionally, on page 4 of Proposed RLPC document, an incorrect acronym **RPLC** is used in the header.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees and will clarify this issue as the project develops.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT understands the need to address the existing inconsistencies among different interconnections with respect to the current RCC criteria, but does not necessarily agree with the proposed approach.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
We appreciate the new consistent approach applied between all interconnections.	
Likes 0	
Dislikes 0	
Response	
Thank you for your supportive comment.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SERC, Group Name SPP Standards Review Group	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with using the two Most Severe Single Contingencies (MSSCs) in each Interconnection as the basis for an Interconnection's IFRO? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

Summary Responses:

The SDT is proposing the N-2 methodology which is in place today for every Interconnection, with the exception of the Eastern Interconnection. Ultimately, the SDT is defining a methodology that identifies the magnitude needed to protect the reliability of the Interconnection. The RLPC value should always equal or exceed the largest N-2 Event. If the RLPC is set equal to or larger than the largest N-2 Event, the probability of an underfrequency load shedding event stays the same or decreases. The methodology provides an RLPC greater than or equal to the largest N-2 Event for each Interconnection. The SDT will provide detailed explanation as the project develops.

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT disagrees in principle with the proposed approach of using the two largest units as a credible contingency, primarily because the probability of two units located hundreds of miles apart tripping on a single initiating event is extremely low. This is not a credible risk that should be addressed by the NERC standards. Depending on how the RLPC is determined, if a large Generator or a DC Tie were to be interconnected hundreds of miles away from another large Generator, the proposed RLPC definition would require ERCOT to procure significant additional reserves at great expense in order to protect UFLS against the proposed RLPC.	
Likes 0	
Dislikes 0	
Response	

The SDT appreciates the concern, but at this time the SDT is proposing the N-2 methodology which is in place today for every Interconnection, with the exception of the Eastern Interconnection. Ultimately, the SDT is defining a methodology that identifies the magnitude needed to protect the reliability of the Interconnection. The RLPC value should always equal or exceed the largest N-2 Event. If the RLPC is set equal to or larger than the largest N-2 Event, the probability of an underfrequency load shedding event stays the same or decreases. The methodology provides an RLPC greater than or equal to the largest N-2 Event for each Interconnection. The SDT will provide detailed explanation as the project develops.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF	
Answer	No
Document Name	
Comment	
As it is uncertain where the industry will trend in future years in terms of new resource sizing and large resource retirements, there is the possibility that the magnitude of the Most Severe Single Contingencies will get smaller and possibly more will be based upon loss of transmission. Duke Energy suggests that the drafting team consider basing the IFRO on the greater of a fixed percentage of the minimum Interconnection load or the two Most Severe Single Contingencies.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT understands your concern and will conduct discussions regarding your comment during Phase II of the project.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	No
Document Name	
Comment	

MSSC may result in calculating IFRO that is insufficient to cover actual Interconnection events as previously stated. Joint owned units provide one example of using MSSC and achieving a non-conservative IFRO value. Another example relates to loss of DC ties, where total transfer may be distributed among multiple BAs resulting in MSSCs being smaller than the Interconnection contingency.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT understands your concern and will address it during development of the project.	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
There is no technical justification for using two MSScs as one of the basis for IFRO. We cannot support going to a MSSC approach without strong technical analysis and supporting historical data. One suggestion is that there could be an actual event where two concurrent MSSCs exceed the single N-2 then the MSSC could become the basis for 3 years.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Ultimately, the SDT is defining a methodology that identifies the magnitude needed to protect the reliability of the Interconnection. The RLPC value should always equal or exceed the largest N-2 Event. If the RLPC is set equal to or larger than the largest N-2 Event, the probability of an underfrequency load shedding event stays the same or decreases. The methodology provides an RLPC greater than or equal to the largest N-2 Event for each Interconnection. The SDT will provide detailed explanation as the project develops.	
Glenn Barry - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No

Document Name	
Comment	

MSSC is a defined term, and if the intent is to look at interconnection resource loss, then using the term MSSC may mislead entities and result in unintended information being submitted and utilized in the IFRO calculation. Perhaps not using MSSC, but defining a different term and providing more clarification and instructions are warranted.

Example 1:

There is a potential gap in reporting JOU/Dynamically scheduled units. LADWP has two JOU that are 900 MW (net) each but only receive 600 MW from each, with the remaining energy sinking in other BAs. It would then be reported as MSSC1 being 600 MW and MSSC2 being 600 MW. In actuality if both units were lost it would be an 1800 MW resource loss to the interconnection, and not the reported 1200 from MSSC 1 and MSSC 2 specified. Since MSSC is a defined term, LADWP would not plan to meet a 900 MW resource loss as MSSC.

Example 2:

This example may be unique to the Western Interconnection and PDCI operation. A BA's operational plans might consider their MSSC as their portion of PDCI schedules (since the sink BA is the reserve responsible entity for schedules that traverse PDCI). For example a sink entity may have an MSSC1 of 2300 MW to represent their maximum PDCI schedules, however this would be not be all of the schedule on PDCI, and also this would be included as part of the N-2 RAS action generation resource loss reported by a separate entity. When taking 2300 MW for MSSC1 + 1500 MW for MSSC 2 for another large unit, then the total result would be 3800 MW, larger than the N-2 RAS of 2850 MW. MSSC is a defined term for reserve planning, which can be different than assessing interconnection resource loss.

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT agrees and will clarify this issue as the project develops.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Although AZPS agrees with the proposal for using the two MSSCs for the basis for an Interconnection's IFRO, it does not believe the current proposed collection method for this data will result in what the SDT intends to collect for the following reasons:

Following the definition of MSSC, a Balancing Authority who is in a RSG would not have a discrete MSSC. As the definition states, an MSSC is a Balancing Contingency Event "within the RSG or a BA's area that is not part of a RSG." Therefore those Balancing Authorities inside an RSG would have nothing to report. Similarly, who will be reporting the MSSC for the RSG since RSGs do not fill out Form 1 and those MSSCs are typically the largest MSSCs.

A good illustration of this collection method concern is Palo Verde nuclear generating units. One of these units total output would not be reported by any RSG or BA area that is not part of a RSG as AZPS is part of an RSG, meaning it does not qualify as an entity who has an MSSC. Hence, this MSSC would not be appropriately captured under the current proposal.

Additionally, if a Balancing Authority inside an RSG is made to report a value, the revised form does not contemplate when a BA has a different MSSC depending on the time of year. One reason this can occur is due to Power Purchase Agreements. A BA's MSSC during one half of the year could be their MSSC2 for the second half of the year. Here is an illustration:

BA1 MSSC1 500 MW (January – June)

BA1 MSSC2 300 MW (January – June)

BA1 MSSC1 600 MW Power Purchase Agreement (July – December)

BA1 MSSC2 500 MW (July – December)

In this example, these two resources cannot be combined to serve as both the MSSC1 and MSSC2 for all times of the year. During January – June the 600 MW unit is BA2's MSSC. If BA1 claims the 600 MW unit as their MSSC, it is likely BA2 will claim it as well, resulting in the unit being counted twice. What should BA1's MSSC1 and MSSC2? For these reasons, AZPS recommends that the SDT review and revise the current proposal regarding the reporting of this information.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees and will clarify this issue as the project develops.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
While having two MSSC events happen at the same time is not statistically probable, using the combination of the two largest MSSCs gives a method for determining a known MW amount that the interconnection should plan for in the case of an extreme event. If it happens to be larger than already studied N-2 events, then the higher IFRO should increase reliability.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	

Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	
AEP believes the proposal leverages existing processes and produces a defendable result.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - SERC,RF, Group Name ISO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SERC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. The standard drafting team is proposing an IFRO methodology that makes changes only when technically justified. This methodology should maintain a stable IFRO rather than implementing immaterial modifications. Do you agree with keeping IFROs stable over time, similar to CPS1, unless Interconnection Frequency Response significantly declines? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

Summary Responses:

The SDT will develop the framework for the technical justification (including metrics) and the process for adjustments. Absent any change in any of the technical parameters, the IFRO will not increase unless there is degradation in actual response. The IFRO can increase based on larger (>10%) change in RLPC annually.

Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	
Though AEP agrees in principal with the overall goal, we must reserve final judgement until more specifics are provided to support the reasoning.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes

Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
We concur with keeping the IFRO methodology stable similar to CPS. At issue is the determination of a significant decline in Frequency Response – will some metric be established? In addition the technical justification of how a significant decline in Frequency Response indicates a challenge to an Interconnections protection in recovering from a N-2 event isn't well established.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees and will develop the framework for the technical justification (including metrics) and the process for adjustments. Absent any change in any of the technical parameters, the IFRO will not increase unless there is degradation in actual response. The IFRO can increase based on larger (>10%) change in RLPC annually.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
BPA understands that the IFRO is calculated based on a statistically derived starting frequency and CBR ratio. In general, BPA agrees that the IFRO need not change for minute statistical changes. However if there is a change to the RLPC that would raise the obligation, it makes sense that the change to IFRO happens quickly in order to protect against this event. It would be good to clarify the language to say that the IFRO stays the same year to year unless there is a significant change in Interconnection Frequency Response Performance, the RLPC, or statistical inputs to the IFRO.	
Likes 0	
Dislikes 0	
Response	
The SDT agrees and will develop the framework for the technical justification and the process for adjustments. Absent any change in any of the technical parameters, the IFRO will not increase unless there is degradation in actual response. The IFRO can increase based on larger (>10%) change in RLPC annually.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes
Document Name	
Comment	
GCPD supports an IFRO methodology that makes changes only when technically justified, and keeps IFRO stable year over year. However, if IFRO is inadequate to respond to actual, or probable, events; IFRO should continue to change annually to provide reliable operation. While it is difficult to respond to this question because the interpretation of when "...Interconnection Frequency Response significantly declines" is nebulous, inadequate IFRO may be caused by factors other than a decline in frequency response such as discovering events that demand significantly more IFRO to respond to the size of the loss. (e.g. loss of large amounts of resources related to inverter performance related to distributed energy resources)	

Likes 0	
Dislikes 0	
Response	
The SDT agrees and will develop the framework for the technical justification and the process for adjustments.	
Glenn Barry - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SERC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - SERC,RF, Group Name ISO Standards Review Committee	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	
Document Name	
Comment	
Xcel Energy completely agrees that the changes must be technically justifiable. However, we feel any increase in an Interconnection's IFRO should be driven by actual degradation in an Interconnection's Frequency response and not by a technically unjustified change in the basis.	
Likes 0	
Dislikes 0	
Response	

The SDT agrees and will develop the framework for the technical justification and the process for adjustments. Absent any change in any of the technical parameters, the IFRO will not increase unless there is degradation in actual response. The IFRO can increase based on larger (>10%) change in RLPC annually.

4. The IFRO methodology proposed by the drafting team separates several variables from the annual modification of the IFRO, including the C to B ratio and delta frequency, and simplifies the calculation. These variables are being reviewed as part of the analysis process that will occur outside of the standard. Do you agree with the separation of the variables from the annual calculation? If you do not agree, or if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

Summary Responses:

Similar to the process used in BAL-001, formulas will be included in the Attachment of the standard; the variables will be maintained outside the Attachment of the standard.

APS provided the following comment: "In the **Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard** it states the RLPC for the Eastern Interconnection is "the largest event in the last 10 years." But the **Proposed Resource Loss Protection Criteria** does not provide for this exception. Please clarify which is correct." The SDT responds: "The largest event in the last 10 years" is being removed and replaced with the RLPC.

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	No
Document Name	
Comment	
If these values are used to determine compliance or to determine mandated values/limits, they should be part of the standard.	
Likes 0	
Dislikes 0	
Response	
The formulas will be included in the Attachment of the standard; the variables will be maintained outside the Attachment of the standard. This is similar to the process used in BAL-001.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	

Answer	No
Document Name	
Comment	
Until phase 2 of this SDT process can occur, BPA does not support changing the core way that IFRO is calculated. In phase 2, the entire methodology of IFRO could be called into question. Until those more thorough discussions happen, it does not make sense to change the IFRO methodology beyond what was suggested for the RLPC. The RLPC should be reviewed annually and IFRO calculated based on the RLPC. Movement towards a new RLPC should be implemented completely, but changes due to small changes in CBR ratio or starting frequency should not require changing the IFRO yearly.	
Likes 0	
Dislikes 0	
Response	
It is the scope of the project SAR to address this issue in Phase 1.	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
These details are an essential part of the standard as they directly impact the determination of a BAs FRM.	
Likes 0	
Dislikes 0	
Response	
The formulas will be included in the Attachment of the standard; the variables will be maintained outside the Attachment of the standard. This is similar to the process used in BAL-001.	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
We cannot support removing these variables (for the MDF calculation in particular) from Attachment A until we see where they will be moved, in terms of new documents, and under what venue this analysis will occur.	
Likes 0	
Dislikes 0	
Response	
The formulas will be included in the Attachment of the standard; the variables will be maintained outside the Attachment of the standard. This is similar to the process used in BAL-001.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
See comments	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	

Answer	Yes
Document Name	
Comment	
In the **Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard** it states the RLPC for the Eastern Interconnection is "the largest event in the last 10 years." But the **Proposed Resource Loss Protection Criteria** does not provide for this exception. Please clarify which is correct.	
Likes 0	
Dislikes 0	
Response	
"The largest event in the last 10 years" is being removed and replaced with the RLPC.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 3,5	
Answer	Yes

Document Name	
Comment	
AEP believes the current methodology could be improved, but simplification itself should not be the primary goal. Rather, the key to success would be to have a well thought-out and documented process.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sean Erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SERC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - SERC,RF, Group Name ISO Standards Review Committee	
Answer	
Document Name	
Comment	
See response to Question 7 and also see attached comments	
Likes 0	
Dislikes 0	
Response	
Please see responses to Question 7.	

5. With the modification to the RLPC and IFRO methodologies, the Eastern Interconnection IFRO will experience an approximate 28 percent decrease, and Hydro Quebec will experience an approximate 17 percent increase. The standard drafting team recommends limiting the IFRO changes by no more than 10 percent annually and implementing percentage of change over the time period necessary to achieve the appropriate IFRO levels. Once the transition is complete, modifications to IFRO would not be limited. Do you agree with this staged implementation of the methodology?

Summary Responses:

Based on comments received, the SDT will be recommending that a decrease to the IFRO will be stepped-in to allow evaluation, and an increase to the IFRO will be implemented in a single step.

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
There's no justification for establishing a lower FRO for an Interconnection whose MSSC1 and MSSC2 clearly indicate that more FRO is needed to protect that Interconnection from the currently defined event. If during this phase in an event occurs that the Interconnection can't respond to is NERC willing to accept the responsibility for requiring less when clearly more was needed?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Based on comments received, the SDT will be recommending that a decrease to the IFRO will be stepped-in to allow evaluation, and an increase to the IFRO will be implemented in a single step.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No

Document Name	
Comment	

BPA thinks that the staged approach makes sense if the IFRO is lowering. If the IFRO is increasing then the change should happen immediately to support reliability.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Based on comments received, the SDT will be recommending that a decrease to the IFRO will be stepped-in to allow evaluation, and an increase to the IFRO will be implemented in a single step.

Sean Erickson - Western Area Power Administration - 1,6

Answer	No
Document Name	
Comment	

The Purpose as written for BAL-003 is: To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.

The question as written would suggest, "*except when the delta is large*".

If the intent is to limit the decrease in the East as a conservative precaution, then YES, WAPA does agree, **but to allow less than required when the new methodology dictates a need for more violates the purpose of the standard**.

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. Based on comments received, the SDT will be recommending that a decrease to the IFRO will be stepped-in to allow evaluation, and an increase to the IFRO will be implemented in a single step.	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	No
Document Name	
Comment	
The concept of this question is wrong on several levels. First, if the new methodology is technically sound - which remains to be shown - then there is every reason to enforce the new IFRO values at the next annual change because the Eastern Interconnection does not need the present amount for reliable operation, and Hydro Quebec has a reliability risk because it is short. Next, what is the technical justification for limiting change to 10% rather than 5%, 7%, 15%, etc.? Does it provide 80% of the benefit at 20% of the cost or achieve some other merit that warrants the risk that is accepted by using a value that is recognized as inadequate? Proposing such a limit calls both the present and proposed methodology into question because one or the other, or perhaps both, must be wrong. Perhaps separate Interconnection methods provide more reliable results, or at least result in less surplus being required by an Interconnection. If Hydro Quebec is reliable today, then there is no need to force them to increase IFRO 17% just to treat all Interconnections the same. Conversely, if they are 17% short, they should correct the deficiency at the next scheduled IFRO change. The real issue is whether the proposed methodology is a better measure to identify necessary IFRO than the old methodology. If so, why?	
Likes 0	
Dislikes 0	
Response	
The SDT will be recommending that a decrease to the IFRO will be stepped-in to allow evaluation, and an increase to the IFRO will be implemented immediately.	
Glenn Barry - Los Angeles Department of Water and Power - 1,3,5,6	

Answer	Yes
Document Name	
Comment	
How was 10% chosen, and is there a basis for that value. It is conservative approach to have staged implementation to large reductions in IFRO. However with IFRO being a reliability measure intended to prevent UFLS what is justification for restricting increases in IFRO greater than 10%?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Based on comments received, the SDT will be recommending that a decrease to the IFRO will be stepped-in to allow evaluation, and an increase to the IFRO will be implemented in a single step.	
Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	
AEP prefers a gradual change of IFRO in response to real changes in the BPS, and we believe the proposed 10 percent is a reasonable annual limit.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT will be recommending that a decrease to the IFRO will be stepped-in to allow evaluation, and an increase to the IFRO will be implemented immediately.

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
As part of the eastern interconnection, we agree with the phased-in approach. This is more impactive with the increasing IFRO but fair to apply the phasing-in in both directions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Based on comments received, the SDT will be recommending that a decrease to the IFRO will be stepped-in to allow evaluation, and an increase to the IFRO will be implemented in a single step.	

Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SERC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	
Document Name	
Comment	

We do not support the 2 MSSC approach and thus have no comment.	
Likes 0	
Dislikes 0	
Response	
Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - SERC,RF, Group Name ISO Standards Review Committee	
Answer	
Document Name	
Comment	
See response to Question 7 and also see attached comments	
Likes 0	
Dislikes 0	
Response	
Please see responses in Question 7.	

6. The drafting team is proposing to move items not related to entity compliance from BAL-003-1.1, Attachment A to the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document. The SAR recommended such changes to Attachment A. Do you agree that the changes to these documents address the SAR recommendations?

Summary Responses:

Similar to the process used in BAL-001, the formulas will be included in the Attachment of the standard; the variables will be maintained outside the Attachment of the standard.

A more complete redline version of the ERO Procedure Document will be included as part of the formal posting and balloting process.

LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	No
Document Name	
Comment	
Requirement 1 requires a BA's FRM to be calculated in accordance with Attachment A, and that its FRM be "...equal to or more negative than its Frequency Response Obligation (FRO)..." Hence, FRO is an obligation and should remain in the standard and subject to the standards drafting process. Keeping the calculations as part of the standard can occur without specifying who is responsible for completing such calculations, though.	
Likes 0	
Dislikes 0	
Response	
The formulas will be included in the Attachment of the standard; the variables will be maintained outside the Attachment of the standard. This is similar to the process used in BAL-001.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No

Document Name	
Comment	
Because the IFRO calculations are the basis for much of the current BAL-003 standard, the IFRO methodology should stay in Attachment A of the standard. Numbers that may change from year to year should move to the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document. However, the methodology and rules for determining and calculating IFRO should stay in the Attachment and not be changed unless it goes through a SAR process.	
Likes 0	
Dislikes 0	
Response	
The formulas will be included in the Attachment of the standard; the variables will be maintained outside the Attachment of the standard. This is similar to the process used in BAL-001.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	No
Document Name	
Comment	
Requirement R1 requires that a "Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO)…." Since the BA's FRM must be equal to or more negative than its FRO, the FRO is a compliance obligation. Compliance obligations should be included in the language of the Standards and Requirements and be subject to the full Standards Drafting Process. LG&E/KU recommends that the IFRO and FRO calculations be set forth in Attachment A without reference to who is responsible for the administrative task of completing the calculations. A similar approach can be seen in BAL-001-2 Attachments 1 and 2 where the equations supporting the Requirements in the Standard are set forth. If the calculations are set forth in Attachment A, then the responsibility for the	

administrative task of completing the calculations can be stated in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document.	
Likes 0	
Dislikes 0	
Response	
The formulas will be included in the Attachment of the standard; the variables will be maintained outside the Attachment of the standard. This is similar to the process used in BAL-001.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
See comments	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Although AZPS agrees in concept to moving these items from Attachment A to the **Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard**, it would be helpful if the SDT would move this language to the procedure and amend the procedure in a proper draft form for proper review by industry. This would avoid errors such as:

- The current posted draft version containing references to itself (last sentence of page 8 "Detailed descriptions of the calculations used in Table 1 below are defined in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.").
- Page 4 under subtitle "Monthly", the link cited is no longer valid.
- There are new items that are not redlined, which does not allow the reviewer to recognize what are new concepts.

Moving the **Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities** from Attachment A to the **Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard** would be another recommended change since these dates and tasks have changed and have not always been adhered to.

To allow industry to properly review and evaluate the proposed document, we recommend, at a minimum, an accurate clean version be provided and possibly a redlined version if a meaningful approximation can be constructed.

Likes 0	
Dislikes 0	
Response	
A more complete redline version of the ERO Procedure Document will be included as part of the formal posting and balloting process.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
No Comments	

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Acceptable to move non entity compliance (including non IFRO) to the "Procedure...." document.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Thomas Foltz - AEP - 3,5	
Answer	Yes
Document Name	
Comment	
AEP agrees in principle with the concept. To be acceptable, the "Procedure" would need to have well-defined steps, boundaries to the use of engineering judgement, clear roles, clear responsibilities, and oversight.	
Likes 0	

Dislikes 0	
Response	
Thank you for your support. A more complete redline version of the ERO Procedure Document will be included as part of the formal posting and balloting process.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Erickson - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SERC, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - SERC,RF, Group Name ISO Standards Review Committee	
Answer	
Document Name	
Comment	
See response to Question 7 and also see attached comments	
Likes 0	
Dislikes 0	
Response	
Please see responses in Question 7.	

7. Please provide any additional comments for the SDT to consider that you have not already provided on the Phase I modifications to BAL-003-1.1.

Summary Responses:

Based on comments received, the SDT will be recommending that a decrease to the IFRO will be stepped-in to allow evaluation, and an increase to the IFRO will be implemented in a single step.

Several commenters requested removal of the statement "The MSSC calculation is done in Real-time operations based on actual system configuration" in the *Proposed Resource Loss Protection Criteria.* While MSSC is updated based on actual system conditions, not all entities calculate MSSC in the manner stated. The SDT will address this in the next version.

Thomas Foltz - AEP - 3,5	
Answer	
Document Name	
Comment	
While we appreciate the drafting team's need for input regarding their efforts, a 14 day turnaround time is not adequate opportunity for industry to provide thoughtful, meaningful feedback on the subject matter.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	

Answer	
Document Name	
Comment	
No Comments	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	
Document Name	
Comment	
The document *Proposed Resource Loss Protection Criteria* states, "The MSSC calculation is done in Real-time operations based on actual system configuration." This statement is not universally accurate and should be removed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT will address this in the next version.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO,SERC, Group Name SPP Standards Review Group	
Answer	

Document Name	
Comment	
The SPP Standards Review Group ("SSRG") requests the Standards Drafting Team revise the definition of "Balancing Contingency Event" to include parameters that will expand the single contingencies recognized as a Most Severe Single Contingency ("MSSC"). For example, non-traditional criteria such as a fuel supply with a single point of failure, Joint Owned Units, and multiple units with a common bus should be included as a BCE, so that this additional granularity may be recognized by the BA as a MSSC.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Revising the definition of Balancing Contingency Event is outside the scope of this project.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
To reiterate, BPA is in support of replacing the RLPC so that it is consistent across all interconnections and that the RLPC should be either the largest credible N-2 resource loss event or the sum of the two largest MSSC's in an interconnection. BPA supports only changing the IFRO if the RLPC changes, there is a substantial decrease in interconnection performance, or there are statistically significant change in the statistical inputs to the IFRO like the CBR ratio, Starting Frequency, etc. Aside from adjusting the RLPC, BPA thinks no changes should be made to the core IFRO methodology until Phase 2 of this SAR and that the methodology for the IFRO should be documented in Attachment A of the BAL-003 standard. The IFRO It serves as the basis for the current standard and the core methodology should not change until further discussions are had in the drafting process.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comments. Based on comments received, the SDT will be recommending that a decrease to the IFRO will be stepped-in to allow evaluation, and an increase to the IFRO will be implemented in a single step.	
Sean Erickson - Western Area Power Administration - 1,6	
Answer	
Document Name	
Comment	
thank you	
Likes 0	
Dislikes 0	
Response	
LeRoy Patterson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	
Document Name	
Comment	
The "Proposed Resource Loss Protection Criteria" states, “The MSSC calculation is done in Real-time operations based on actual system configuration.” While MSSC is updated based on actual system conditions, not all entities calculate MSSC in the manner stated. Please modify or remove this statement.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT will address this in the next version.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	
Document Name	
Comment	
IFRO calculation description is somewhat confusing. The last sentence in the first paragraph says: “A maximum delta frequency (MDF) is calculated by adjusting a starting frequency for each Interconnection by the following: “ The above sentence is implying that the starting frequency is adjusted by the items which follow up. Is the intent of the sentence is to say that MDF calculation depends upon the follow up items? I do not see how the follow up items adjust the starting frequency? Also, it is not clear how the starting frequency is chosen in Table 1. Please clarify. Also it would help to clarify the basis of CLR values.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT will address this in the next version.	
Albert DiCaprio - PJM Interconnection, L.L.C. - 2 - SERC,RF, Group Name ISO Standards Review Committee	
Answer	
Document Name	Bal-003 (IRC Standards Review Committee without ERCOT).docx
Comment	

Comment 1:

The drafting team is trying to replicate the process used for CPS1. The performance level for CPS1 is based on a parameter called epsilon 1 (e1). The BAL-001 standard was designed such that if frequency performance of the grid degraded, NERC would work with the NERC OC and its subcommittees to identify a new e1 to tighten performance.

In the nearly 20 years of existence, there never has been a need to tighten the BAL-001 and only one case where an Interconnection went through the process to increase their e1.

Under the current version of the BAL-003 standard, NERC has to annually file a detailed analysis and suggest changes to the obligations. Interestingly, the math for the analysis suggests that since the "B value" in the East has improved, its obligation needs to go up. Additionally, there was no "off ramp" in the standard for the East's 4500MW contingency that was the largest in 10 years.

The drafting team was hoping remove the hardcoding in the BAL-003 attachment and set up a process similar to BAL-001 whereby a reasonable target obligation for an Interconnection would only change it if:

- Performance drops below a base year by 10%.
- A new larger credible contingency is identified in an Interconnection.
- For cases like ERCOT where they use interruptible load as a resource, to adjust if the amount of contracted load changes.

Comment 2:

- The proposed process is flexible enough to allow the ERO to calculate the mandated values for BAL-003 BUT this process should remain as part of the official Attachment to the Standard (and not be made a Guideline). I propose this because of concerns with how "adjustments" are made. It appears that adjustments come from a small group of people who could be impacted by one or two regions thus those adjustments should be open to the public. For example, there is an adjustment for load (i.e. Credit for Load) value for load that is shed above the minimum UFLS. For the east the UFLS point itself is raised because of the local UFLS of Florida, whereas others are getting credit for this load shedding. This matter should be discussed by the Industry and not simply "include" in a calculation.

- Terry's point about the new process being a good step forward is correct. I do believe that the process can be further enhanced if the proposed SDT changes strictly followed their own approach as opposed to having "off-ramps" for changes that indicated more than just marginal changes over a year. And if this approach were to follow a strict simple formula, all of the all too many references to "except for the EI" would be eliminated and replaced with a defined reliability obligation. As it is today the proposal fails to recognize that the EI frequency performance is in many ways better than other interconnection's performance. This issue should be discussed in open as part of the formal process or even better as part of an ongoing informal process.
- Terry's point about the lack of change over the years also points to the fact that the process should continue to be part of the standard (if the system is stable then sudden changes to the Process should be rare and openly discussed) and any changes should be subject to Industry discussion vis-à-vis a SAR.
- Terry's point about the use of the two Most Severe
- The Procedure language is itself too casual and should be made more direct. The comments in this draft will hopefully add to that clarity.

{C}o {C}What is BETA?

{C}o {C}M-4 Point C is a Section heading not a value

{C}o {C}Are variables "Points" or "Values"

{C}o {C}Who reports the Most Severe Single Contingency (from section "Changes in Resource Loss Protection" in the ADJUSTMENTS TO INTERCONNECTION FREQUENCY BIA OBLIGATION Guideline

{C}§ {C}The RC who has all of the data but does not necessarily have all of the detailed "changes"

{C}§ {C}The GO who has responsibility for generating resource capacity

{C}§ {C}The TOP who has information on transmission related impacts

{C}§ {C}The PC who has forecast information

{C}o {C}Is the reporting of the largest resources an Annual calculation of a “daily” calculation (It seems from the text that this may be done each day as he resources change)

In short, the proposal has good intentions but it stills needs work in how it is written and how it can be made even better. (see attached relined document)

Comment 3:

The RLPC should be what it is and then it should be parenthetically noted that it happened to be the largest category C event… We should not lock ourselves into using only the largest category C event for the preceding 10 years – it varies too much.

The Credit for Load is not applicable to firm load shed. ERCOT receives the credit because ERCOT has a robust competitive market for demand response to provide response in less than 30 cycles to arrest frequency decay. Any applicable entity that has a demand response program designed to arrest large frequency deviation that responds before UFLS trigger is eligible for credit. Not assigning the LR credit would cause to IFRO requirement to almost more than double while trying to protect against the same RCC or RLPC.

Likes 0	
Dislikes 0	

Response

Thank you for your comments and suggestions. The SDT will be taking your comments and suggestions into consideration as the project continues to develop.

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

No response.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	
We support the changes as they represent a more stream-lined standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the second draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	04/18/2018
SAR posted for comment	03/19/2018 – 03/28/2018

Anticipated Actions	Date
45-day formal or informal comment period with ballot	11/26/2018 – 01/09/2019
45-day formal or informal comment period with additional ballot	TBD
10-day final ballot	TBD
Board adoption	TBD

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title: Frequency Response and Frequency Bias Setting**

2. **Number:** **BAL-003-2**

3. **Purpose:** To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authority

   4.1.1.1. Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.

   4.1.2. Frequency Response Sharing Group

5. **Effective Date:** See Implementation Plan for BAL-003-2.

B. Requirements and Measures

R1. Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) 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. *[Risk Factor: High][Time Horizon: Real-time Operations]*

M1. Each Frequency Response Sharing Group or Balancing Authority that is not a member of a Frequency Response Sharing Group shall have evidence such as dated data plus documented formula in either hardcopy or electronic format that it achieved an annual FRM (in accordance with the methods specified by the ERO in Attachment A with data from FRS Form 1 reported to the ERO as specified in Attachment A) that is equal to or more negative than its FRO to demonstrate compliance with Requirement R1.

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 in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. *[Risk Factor: Medium][Time Horizon: Operations Planning]*

M2. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service shall have evidence such as a dated document in hard copy or electronic format showing the ERO validated Frequency Bias Setting was implemented into its ACE calculation within the implementation period specified or other evidence to demonstrate compliance with Requirement R2.

R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

3.1 Less than zero at all times, and

3.2 Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.

M3. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and is utilizing variable Frequency Bias shall have evidence such as a dated report in hard copy or electronic format showing the average clock-minute average Frequency Bias Setting was less than zero and during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was equal to or more negative than its Frequency Response Obligation to demonstrate compliance with Requirement R3.

R4. 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 to either: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

- The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or

- The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.

M4. The Balancing Authority shall have evidence such as a dated operating log, database or list in hard copy or electronic format showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation as specified in Requirement R4 to demonstrate compliance with Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

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

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If a Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.
- The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or

information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

- For Interconnections that are also Balancing Authorities, Tie Line Bias control and flat frequency control are equivalent and either is acceptable.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1% but by at most 15% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 15% but by at most 30% or by more than 30 MW/0.1 Hz, whichever is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 30% but by at most 45% or 45 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 45% or by more than 45 MW/0.1 Hz, whichever is the greater deviation from its FRO.
R2.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting failed to implement the validated Frequency Bias Setting value into its ACE calculation within the implementation period specified but did so within 5 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 5 calendar days but less than or equal to 15 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 15 calendar days but less than or equal to 25 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting did not implement the validated Frequency Bias Setting value into its ACE calculation in more than 25 calendar days from the implementation period specified by the ERO.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 1% but by at most 10%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 10% but by at most 20%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 20% but by at most 30%.	The Balancing Authority that is a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response obligation by more than 30%.
R4.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error less than or equal to 10% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 10% but less than or equal to 20% of the	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 20% but less than or equal to 30% of the	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 30% of the validated or calculated value. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		validated or calculated value.	validated or calculated value.	The Balancing Authority failed to change the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services.

D. Regional Variances

None.

E. Associated Documents

[Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard]

FRS Form 1

FRS Form 2

[Frequency Response Standard Background Document]

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	March 16, 2007	FERC Approval — Order 693	New
0a	December 19, 2007	Added Appendix 1 — Interpretation of R3 approved by BOT on October 23, 2007	Addition
0a	July 21, 2008	FERC Approval of Interpretation of R3	Addition
0b	February 12, 2008	Added Appendix 2 — Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition
0.1b	January 16, 2008	Section F: added "1."; changed hyphen to "en dash." Changed font style for "Appendix 1" to Arial; updated version number to "0.1b"	Errata
0.1b	October 29, 2008	BOT approved errata changes	Errata
0.1a	May 13, 2009	FERC Approved errata changes – version changed to 0.1a (Interpretation of R2, R2.2, R5, and R5.1 not yet approved)	Errata
0.1b	May 21, 2009	FERC Approved Interpretation of R2, R2.2, R5, and R5.1	Addition
1	February 7, 2013	Adopted by NERC Board of Trustees	Complete Revision under Project 2007-12
1	January 16, 2014	FERC Order issued approving BAL-003-1. (Order becomes effective for R2, R3, and R4 April 1, 2015. R1 becomes effective April 1, 2016.)	
1	May 7, 2014	NERC Board of Trustees adopted revisions to VRF and VSLs in Requirement R1.	
1	November 26, 2014	FERC issued a letter order approved VRF and VSL revisions to Requirement R1.	
1.1	August 25, 2015	Added numbering to Introduction section, corrected parts numbering for R3, and adjusted font within section M4.	Errata

Version	Date	Action	Change Tracking
1.1	November 13, 2015	FERC Letter Order approved errata to BAL-003-1.1. Docket RD15-6-000	Errata

Standard Attachments

Attachment A

BAL-003-2 Frequency Response and Frequency Bias Setting Standard

Supporting Document

Interconnection Frequency Response Obligation

The ERO, in consultation with regional representatives, has established a target reliability criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). Detailed descriptions of the calculations used in Table 1 below are defined in the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.

Interconnection	Eastern	Western	ERCOT	HQ	Units
Max. Delta Frequency (MDF)	**0.419**	**0.280**	**0.406**	**0.946**	
Resource Loss Protection Criteria (RLPC)*	**3,209**	**2,850**	**2,750**	**2,000**	MW
Credit for Load Resources (CLR)		**120**	**1,209**		MW
Current IFRO (OY 2018)	**-1,015**	**-858**	**-381**	**-179**	MW/0.1 Hz
First-Step IFRO**	**-915**	**-975**	**-380**	**-211**	MW/0.1 Hz
Second-Step IFRO**	**-815**				
Final IFRO**	**-766**				

Table 1: Interconnection Frequency Response Obligations (base year)

**These values are evaluated annually for changes in each Interconnection.*

***To reduce risk, the Eastern Interconnection IFRO will be stepped down annually from the 2017 value of -1,015 MW/0.1 Hz in -100 MW/0.1 Hz increments. If during the step down process, Interconnection Frequency Response Measure (FRM) declines by more than 10 percent, the ERO will halt the reduction in IFRO until such time that a determination can be made as to the cause of the degradation.*

Balancing Authority Frequency Response Obligation and Frequency Bias Setting

For a multiple Balancing Authority interconnection, the Interconnection FRO shown in Table 1 is allocated based on the Balancing Authority annual load and annual generation. The FRO allocation will be based on the following method:

$$\mathrm{FRO_{BA}} = \mathrm{IFRO} \quad \times \frac{\text{Annual Gen}_{\text{BA}} + \text{Annual Load}_{\text{BA}}}{\text{Annual Gen}_{\text{Int}} + \text{Annual Load}_{\text{Int}}}$$

Where:

- Annual Gen_{BA} is the total annual output of generating plants within the Balancing Authority Area (BAA).
- Annual $Load_{BA}$ is total annual Load within the BAA.
- Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that interconnection.
- Annual $Load_{Int}$ is the sum of all Annual $Load_{BA}$ values reported in that interconnection.

Balancing Authorities that elect to form a FRSG will calculate a FRSG FRO by adding together the individual BA FRO's.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Submit a joint Form 1 with the "FRSG" tab completed for the aggregate performance of the participating Balancing Authorities.

Balancing Authorities that merge or transfer load or generation are encouraged to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation to the Interconnection remains the same and so that CPS limits can be adjusted.

Each Balancing Authority reports its previous year's FRM, Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised Frequency Bias Settings on FRS Form 1. In addition, each Balancing Authority will report its two largest potential resource losses and any applicable N-2 RAS events in the form. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities will be given 30 days from the date the ERO posts the official list of events to submit their FRS Form 1.

Once the ERO reviews the data submitted in FRS Form 1 and FRS Form 2 for all Balancing Authorities, the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year:

- Frequency Bias Setting
- Frequency Response Obligation (FRO)

Once the data listed above is fully posted, the ERO will announce the three-day implementation period for changing the Frequency Bias Setting if it differs from that shown in the timeline below.

A Balancing Authority using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value):

- Any number the Balancing Authority chooses between 100 percent and 125 percent of its Frequency Response Measure as calculated on FRS Form 1
- Interconnection Minimum as determined by the ERO

For purposes of calculating the minimum Frequency Bias Setting, a Balancing Authority participating in a FRSG will need to calculate its stand-alone FRM using FRS Form 1 and FRS Form 2 to determine its minimum Frequency Bias Setting.

A Balancing Authority providing Overlap Regulation will report the historic peak demand and generation of its combined Balancing Authorities' areas on FRS Form 1 as described in Requirement R4.

Frequency Response Measure

The Balancing Authority will calculate its FRM from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event in a Balancing Authority area that is used to calculate its Frequency Response, expressed in MW/0.1Hz" as calculated on FRS Form 2 for each event shown on FRS Form 1. The events in FRS Form 1 are selected by the ERO using the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is the change in its Net Actual Interchange on its tie lines with adjacent Balancing Authorities divided by the change in Interconnection frequency. Some Balancing Authorities may choose to apply corrections to their Net Actual Interchange (NA_I) values to account for factors such as nonconforming loads. FRS Form 1 and 2 shows the types of adjustments that are allowed. Note that with the exception of the Contingent BA column, any adjustments made must be made for all events in an evaluation year.[1]

The ERO will use a standardized sampling interval of approximately 16 seconds before the event, up to the time of the event for the pre-event NA_I, and frequency (A values), and approximately 20 to 52 seconds after the event for the post-event NA_I (B values) in the computation of SEFRD values, dependent on the data scan rate of the Balancing Authority's Energy Management System (EMS).

All events listed on FRS Form 1 need to be included in the annual submission of FRS Forms 1 and 2. The only time a Balancing Authority should exclude an event is if its tie-line data or its Frequency data is corrupt, or its EMS was unavailable. FRS Form 2 has instructions on how to

[1] As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.

correct the BA's data if the given event is internal to the BA or if other authorized adjustments are used.

Assuming data entry is correct, FRS Form 1 will automatically calculate the Balancing Authority's FRM for the past 12 months as the median of the SEFRD values. A Balancing Authority electing to report as an FRSG or a provider of Overlap Regulation Service will provide an FRS Form 1 for the aggregate of its participants.

To allow Balancing Authorities to plan its operations, events with a "Point C" that cause the Interconnection Frequency to be lower than that shown in Table 1 above (for example, an event in the Eastern Interconnection that causes the Interconnection Frequency to go to 59.4 Hz) or higher than an equal change in frequency going above 60 Hz may be included in the list of events for that Interconnection. However, the calculation of the Balancing Authority response to such an event will be adjusted to show a frequency change only to the Target Minimum Frequency shown in Table 1 above (in the previous example this adjustment would cause Frequency to be shown as 59.5 Hz rather than 59.4 HZ) or a high frequency amount of an equal quantity. Should such an event happen, the ERO will provide additional guidance.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual Balancing Authority's Form 1s, with a summary spreadsheet that contains the sum of each participant's individual event performance.

Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities

Described below is the timeline for the exchange of information between the ERO and Balancing Authorities to:

- Facilitate the assignment of Balancing Authority FRO
- Calculate Balancing Authority FRM
- Determine Balancing Authority Frequency Bias Settings

Target Business Date	Activity
March 1	FRS Form 1 is posted by the ERO* with all selected events for the operating year for BA usage.
April 1	BAs and FRSGs complete their frequency response forms for all four quarters, including the BAs' FBS calculations, returning the results to the ERO.
May 1	The ERO validates FBS values, computes the sum of all FBS values for each Interconnection.
May 15	The BAs not required to file FERC Form 714 receive a request to provide load and generation data as described in the ***Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard***** to support FRO assignments and determining minimum FBS for the upcoming year. Data to be provided by July 15.
June 1	The BA implements any changes to their FBS.
November 1	The ERO assigns FRO values and Minimum FBS for the upcoming year to the BAs.

* If 4th quarter posting of FRS Form 1s is delayed, the ERO may adjust the other timelines in this table by a similar amount.

** Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

~~15-day informal comment period~~ This is the second draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	04/18/2018
SAR posted for comment	03/19/18 – 03/28/18

Anticipated Actions	Date
~~XX~~45-day formal or informal comment period with ballot	11/26/2018 – 01/09/2019
~~XX~~45-day formal or informal comment period with additional ballot	TBD
~~XX~~10-day final ballot	TBD
Board adoption	TBD

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

Upon Board adoption, the rationale boxes will be moved to the Supplemental Material Section.

A. Introduction

1. **Title: Frequency Response and Frequency Bias Setting**
2. **Number: BAL-003-~~1.1~~2**
3. **Purpose:** To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Balancing Authority
       - **4.1.1.1.** Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.
     - **4.1.2.** Frequency Response Sharing Group
5. **Effective Date:** See Implementation Plan for BAL-003-~~1.1~~2.

B. Requirements and Measures

R1. Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) 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. *[Risk Factor: High][Time Horizon: Real-time Operations]*

M1. Each Frequency Response Sharing Group or Balancing Authority that is not a member of a Frequency Response Sharing Group shall have evidence such as dated data plus documented formula in either hardcopy or electronic format that it achieved an annual FRM (in accordance with the methods specified by the ERO in Attachment A with data from FRS Form 1 reported to the ERO as specified in Attachment A) that is equal to or more negative than its FRO to demonstrate compliance with Requirement R1.

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 in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. *[Risk Factor: Medium][Time Horizon: Operations Planning]*

M2. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service shall have evidence such as a dated document in hard copy or electronic format showing the ERO validated Frequency Bias Setting was implemented into its ACE calculation within the implementation period specified or other evidence to demonstrate compliance with Requirement R2.

R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

3.1 Less than zero at all times, and

3.2 Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.

M3. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and is utilizing variable Frequency Bias shall have evidence such as a dated report in hard copy or electronic format showing the average clock-minute average Frequency Bias Setting was less than zero and during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was equal to or more negative than its Frequency Response Obligation to demonstrate compliance with Requirement R3.

R4. 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 to either: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

- The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or
- The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.

M4. The Balancing Authority shall have evidence such as a dated operating log, database or list in hard copy or electronic format showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation as specified in Requirement R4 to demonstrate compliance with Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

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

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If a Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.
- The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or

information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

- For Interconnections that are also Balancing Authorities, Tie Line Bias control and flat frequency control are equivalent and either is acceptable.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1% but by at most ~~30~~15% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 15% but by at most 30% or by more than ~~15~~ 30 MW/0.1 Hz, whichever is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than ~~1~~30% but by at most ~~30~~45% or ~~15~~ 45 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than ~~30~~45% or by more than ~~15~~ 45 MW/0.1 Hz, whichever is the greater deviation from its FRO.
R2.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting failed to implement the validated Frequency Bias Setting value into its ACE calculation within the implementation period specified but did so within 5 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 5 calendar days but less than or equal to 15 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 15 calendar days but less than or equal to 25 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting did not implement the validated Frequency Bias Setting value into its ACE calculation in more than 25 calendar days from the implementation period specified by the ERO.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 1% but by at most 10%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 10% but by at most 20%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 20% but by at most 30%.	The Balancing Authority that is a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response obligation by more than 30%.
R4.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error less than or equal to 10% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 10% but less than or equal to 20% of the	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 20% but less than or equal to 30% of the	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 30% of the validated or calculated value. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		validated or calculated value.	validated or calculated value.	The Balancing Authority failed to change the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services.

D. Regional Variances

None.

E. Associated Documents

~~Link to the Implementation Plan and other important associated documents.~~

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

FRS Form 1

FRS Form 2

Frequency Response Standard Background Document

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	March 16, 2007	FERC Approval — Order 693	New
0a	December 19, 2007	Added Appendix 1 — Interpretation of R3 approved by BOT on October 23, 2007	Addition
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Version	Date	Action	Change Tracking
1.1	November 13, 2015	FERC Letter Order approved errata to BAL-003-1.1. Docket RD15-6-000	Errata

Standard Attachments

Attachment A

BAL-003-~~1~~ 2 Frequency Response ~~&~~ and Frequency Bias Setting Standard

Supporting Document

Interconnection Frequency Response Obligation ~~(IFRO)~~

The ERO, in consultation with regional representatives, has established a target ~~contingency protection criterion~~reliability ~~objective~~criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). ~~The default IFRO listed in Table 1 is based on the resource contingency criteria (RCC), which is the largest category C (N-2) event identified except for the Eastern Interconnection, which uses the largest event in the last 10 years. A maximum delta frequency (MDF) is calculated by adjusting a starting frequency for each Interconnection by the following:~~

~~Prevailing UFLS first step~~

- ~~CC_{Adj} which is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data~~
- ~~CB_R which is the statistically determined ratio of the Point C to Value B~~
- ~~BC'_{Adj} which is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.~~

~~The IFRO for each Interconnection in Table 1 is then calculated by dividing the RCC MWs by 10 times the MDF. In the Eastern Interconnection there is an additional adjustment (BC'_{Adj}) for the event nadir being below the Value B due to primary frequency response withdrawal. This IFRO includes uncertainty adjustments at a 95 % confidence level.~~ Detailed descriptions of the calculations used in Table 1 below are defined in the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.

Interconnection	Eastern	Western	ERCOT	HQ	Units
~~Starting Frequency (F_{Start})~~	~~59.974~~	~~59.976~~	~~59.963~~	~~59.972~~	~~Hz~~
~~Prevailing UFLS First Step~~	~~59.5*~~	~~59.5~~	~~59.3~~	~~58.5~~	~~Hz~~
~~Base Delta Frequency (DF_{Base})~~	~~0.474~~	~~0.476~~	~~0.663~~	~~1.472~~	~~Hz~~
~~CC_{ADJ}~~	~~0.007~~	~~0.004~~	~~0.012~~	~~N/A~~	~~Hz~~
~~Delta Frequency (DF_{CC})~~	~~0.467~~	~~0.472~~	~~0.651~~	~~1.472~~	~~Hz~~
~~CB_R~~	~~1.000~~	~~1.625~~	~~1.377~~	~~1.550~~	
~~Delta Frequency (DF_{CBR})~~	~~0.467~~	~~0.291~~	~~0.473~~	~~0.949~~	~~Hz~~
~~BC'_{ADJ}~~	~~0.018~~	~~N/A~~	~~N/A~~	~~N/A~~	~~Hz~~
Max. Delta Frequency (MDF)	0.419~~49~~	0.280~~91~~	0.406~~73~~	0.946~~9~~	

Resource ~~Contingency~~ Loss Protection Criteria (RLP~~C~~C)*	34,209~~500~~	2,85~~74~~0	2,750	2~~1~~,0~~7~~00	MW
Credit for Load Resources (CLR)		120~~300~~	1,209~~,400**~~		MW
Current IFRO (OY 2018)	-1,015	-858	-381	-179	MW/0.1 Hz
First-Step IFRO**~~IFRO~~	-915~~-1,002~~	-975~~840~~	-380~~286~~	-211~~179~~	MW/0.1 Hz
Second-Step IFRO**	-815				
Final IFRO**	-766				

Table 1: Interconnection Frequency Response Obligations (base year)

*****~~*These values are updated using preliminary information collected by the Standard Drafting Team.*~~*These values are evaluated annually for changes in each Interconnection.*

***To reduce risk, the Eastern Interconnection IFRO will be stepped down annually from the 2017 value of -1,015 MW/0.1 Hz in -100 MW/0.1 Hz increments. If during the step down process, Interconnection Frequency Response Measure (FRM) declines by more than 10~~%~~ percent, the ERO will halt the reduction in IFRO until such time~~s~~ that a determination can be made as to the cause of the degradation~~what is impacting Interconnection FRM~~.*

~~The Eastern Interconnection UFLS set point listed is a compromise value set midway between the stable frequency minimum established in PRC-006-1 (59.3 Hz) and the local protection UFLS setting of 59.7 Hz used in Florida and Manitoba.~~

*~~**In the Base Obligation measure for ERCOT, 1400 MW (Load Resources triggered by Under Frequency Relays at 59.70 Hz) was reduced from its Resource Contingency Criteria level of 2750 MW to get 239 MW/0.1 Hz. This was reduced to accurately account for designed response from Load Resources within 30 cycles.~~*

~~An Interconnection may propose alternate IFRO protection criteria to the ERO by submitting a SAR with supporting technical documentation.~~

Balancing Authority Frequency Response Obligation ~~(FRO)~~ and Frequency Bias Setting

~~The ERO will manage the administrative procedure for annually assigning an FRO and implementation of the Frequency Bias Setting for each Balancing Authority. The annual timeline for all activities described in this section are shown below.~~

For a multiple Balancing Authority interconnection, the Interconnection FRO~~Frequency Response Obligation~~ shown in Table 1 is allocated based on the Balancing Authority annual load and annual generation. ~~-~~The FRO allocation will be based on the following method:

$$\mathrm{FRO_{BA}} = \mathrm{IFRO} \quad \times \frac{\text{Annual Gen}_{\text{BA}} + \text{Annual Load}_{\text{BA}}}{\text{Annual Gen}_{\text{Int}} + \text{Annual Load}_{\text{Int}}}$$

Where:

- Annual Gen_{BA} is the total annual ~~"~~o~~O~~utput of g~~G~~enerating p~~P~~lants~~"~~ within the Balancing Authority Area (BAA).~~, on FERC Form 714, column c of Part II - Schedule 3.~~
- Annual $Load_{BA}$ is total annual Load within the BAA~~, on FERC Form 714, column e of Part II - Schedule 3~~.
- Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that interconnection.
- Annual $Load_{Int}$ is the sum of all Annual $Load_{BA}$ values reported in that interconnection.

~~The data used for this calculation is from the most recently filed Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which utilized data from 2011.~~

~~Balancing Authorities that are not FERC jurisdictional should use the Form 714 Instructions to assemble and submit equivalent data to the ERO for use in the FRO Allocation process.~~

Balancing Authorities that elect to form a FRSG will calculate a FRSG FRO by adding together the individual BA FRO's.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- ~~Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that contains the sum of each participant's individual event performance.~~ Submit a joint Form 1 with

the "FRSG" tab completed for the aggregate performance of the participating Balancing Authorities~~As~~.

Balancing Authorities that merge or ~~that~~ transfer load or generation are encouraged to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation to the Interconnection remains the same and so that CPS limits can be adjusted.

Each Balancing Authority reports its previous year's ~~Frequency Response Measure (~~FRM~~)~~, Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised Frequency Bias Settings on FRS Form 1. In addition, each Balancing Authority will report its two largest potential resource losses and any applicable N-2 RAS events in the form. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities will be given 30 days from the date the ERO posts the official list of events to submit their FRS Form 1.

Once the ERO reviews the data submitted in FRS Form 1 and FRS Form 2 for all Balancing Authorities, the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year:

- Frequency Bias Setting
- Frequency Response Obligation (FRO)

Once the data listed above is fully posted, the ERO will announce the three-day implementation period for changing the Frequency Bias Setting if it differs from that shown in the timeline below.

A Balancing Authority using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value):

- Any number the Balancing Authority chooses between 100~~%~~ percent and 125~~%~~ percent of its Frequency Response Measure as calculated on FRS Form 1
- Interconnection Minimum as determined by the ERO

For purposes of calculating the minimum Frequency Bias Setting, a Balancing Authority participating in a ~~Frequency Response Sharing Group~~FRSG will need to calculate its stand-alone ~~Frequency Response Measure~~FRM using FRS Form 1 and FRS Form 2 to determine its minimum Frequency Bias Setting.

A Balancing Authority providing Overlap Regulation will report the historic peak demand and generation of its combined Balancing Authorities' areas on FRS Form 1 as described in Requirement R4.

~~There are occasions when changes are needed to Bias Settings outside of the normal schedule. Examples are footprint changes between Balancing Authorities and major changes in load or generation or the formation of new Balancing Authorities. In such cases the changing Balancing Authorities will work with their Regions, NERC and the Resources Subcommittee to confirm appropriate changes to Bias Settings, FRO, CPS limits and Inadvertent Interchange balances.~~

~~If there is no net change to the Interconnection total Bias, the Balancing Authorities involved will agree on a date to implement their respective change in Bias Settings. The Balancing Authorities and ERO will also agree to the allocation of FRO such that the sum remains the same.~~

~~If there is a net change to the Interconnection total Bias, this will cause a change in CPS2 limits and FRO for other Balancing Authorities in the Interconnection. In this case, the ERO will notify the impacted Balancing Authorities of their respective changes and provide an implementation window for making the Bias Setting changes.~~

~~The ERO, in consultation with regional representatives, has established a target contingency protection criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). Detailed descriptions of the IFRO calculations are defined in the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.[1]~~

Frequency Response Measure ~~(FRM)~~

The Balancing Authority will calculate its FRM from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event ~~from~~ in a Balancing Authority area that is used to calculate its Frequency Response, expressed in MW/0.1Hz" as calculated on FRS Form 2 for each event shown on FRS Form 1. The events in FRS Form 1 are selected by the ERO using the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is ~~basically~~ the change in its Net Actual Interchange on its tie lines with ~~its~~ adjacent Balancing Authorities divided by the change in Interconnection frequency. ~~(~~Some Balancing Authorities may choose to apply corrections to their Net Actual Interchange (NA_I) values to account for factors such as nonconforming loads. FRS Form 1 and 2 shows the types of adjustments that are allowed. Note that with the exception of the Contingent BA column, any adjustments made must be made for all events in an evaluation year.[2] ~~As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.)~~

The ERO will use a standardized sampling interval of approximately 16 seconds before the event, up to the time of the event for the pre-event NA_I, and frequency (A values), and approximately 20 to 52 seconds after the event for the post-event NA_I (B values) in the computation of SEFRD values, dependent on the data scan rate of the Balancing Authority's Energy Management System (EMS).

~~[1] Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard is available at https://www.nerc.com/pa/Stand/Frequency%20Response%20Project%20200712%20Related%20Files%20DL/BAL-003-1_Procedure-Clean_20120210.pdf~~

[2] As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.

All events listed on FRS Form 1 need to be included in the annual submission of FRS Forms 1 and 2. The only time a Balancing Authority should exclude an event is if its tie-line data or its Frequency data is corrupt, or its EMS was unavailable. ~~-~~FRS Form 2 has instructions on how to correct the BA's data if the given event is internal to the BA or if other authorized adjustments are used.

Assuming data entry is correct, FRS Form 1 will automatically calculate the Balancing Authority's FRM for the past 12 months as the median of the SEFRD values. A Balancing Authority electing to report as an FRSG or a provider of Overlap Regulation Service will provide an FRS Form 1 for the aggregate of its participants.

To allow Balancing ~~authorities~~ Authorities to plan its operations, events with a "Point C" that cause the Interconnection Frequency to be lower than that shown in Table 1 above (for example, an event in the Eastern Interconnection that causes the Interconnection Frequency to go to 59.4 Hz) or higher than an equal change in frequency going above 60 Hz may be included in the list of events for that ~~interconnection~~Interconnection. However, the calculation of the Balancing Authority response to such an event will be adjusted to show a frequency change only to the Target Minimum Frequency shown in Table 1 above (in the previous example this adjustment would cause Frequency to be shown as 59.5 Hz rather than 59.4 HZ) or a high frequency amount of an equal quantity. Should such an event happen, the ERO will provide additional guidance.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual Balancing Authority's Form 1s, with a summary spreadsheet that contains the sum of each participant's individual event performance.

Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities

Described below is the timeline for the exchange of information between the ERO and Balancing Authorities ~~(BA)~~ to:

- Facilitate the assignment of Balancing Authority ~~Frequency Response Obligations (~~FRO~~)~~
- Calculate Balancing Authority ~~Frequency Response Measures (~~FRM~~)~~
- Determine Balancing Authority A Frequency Bias Settings ~~(FBS)~~

Target Business Date	Activity
~~April 30~~March 1	FRS Form 1 is posted by ~~The~~ the ERO* with all selected events for the operating year for BA usage~~reviews candidate frequency events and selects frequency events for the first quarter (December to February)~~.
April 1	BAs and FRSGs complete their frequency response forms for all four quarters, including the BAs' FBS calculations, returning the results to the ERO.
May 1	The ERO validates FBS values, computes the sum of all FBS values for each Interconnection.
~~May 10~~	~~Form1 is posted with selected events from the first quarter for BA usage by the ERO.~~
May 15	The BAs not required to file FERC Form 714 receive a request to provide load and generation data as described in the ***Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard***** to support FRO assignments and determining minimum FBS for the upcoming year. Data to be provided by July 15.~~The BAs receive a request to provide load and generation data as described in Attachment A to support FRO assignments and determining minimum FBS for BAs.~~
June 1	The BA implements any changes to their FBS.
November 1	The ERO assigns FRO values and Minimum FBS for the upcoming year to the BAs.

* If 4th quarter posting of FRS Form 1s is delayed, the ERO may adjust the other timelines in this table by a similar amount.

** Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

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~~Rationale~~

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

~~Rationale for R1:~~

~~Text, text, text~~

~~Rationale for R2:~~

~~Text, text, text~~

Implementation Plan

Project 2017-01 Modifications to BAL-003-1.1
Reliability Standard BAL-003-2

Applicable Standard

- Standard BAL-003-2 — Frequency Response and Frequency Bias Setting

Requested Retirement(s)

- Standard BAL-003-1.1 — Frequency Response and Frequency Bias Setting

Applicable Entities

- Balancing Authority
  - Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.
- Frequency Response Sharing Group

Background

The BAL-003-2 Phase I portion of the project revises the BAL-003-1.1 standard and process documents to address: (1) the inconsistencies in calculation of IFROs due to interconnection Frequency Response performance changes of Point C and/or Value B; (2) the Eastern Interconnection Resource Contingency Protection Criteria; (3) the frequency of nadir point limitations (currently limited to t0 to t+12); (4) clarification of language in Attachment A, i.e. related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities; and (5) enhancements to the BAL-003-1 FRS Forms that include the ability to collect and submit FRSG performance data. Additionally, the supporting procedural and process steps have been removed from Attachment A and captured in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.* This proposed document would be subject to approval by the North American Electric Reliability Corporation Operating Committee and Board of Trustees, and subject to informational filing with the Federal Energy Regulatory Commission, to facilitate timely process improvements as future lessons are learned.

Effective Date

BAL-003-2 — Frequency Response and Frequency Bias Setting

Where approval by an applicable governmental authority is required, the standard shall become effective on the first operating year (which begins on December 1) that is 90 days after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first operating year (which begins on December 1) that is 90 days after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

BAL-003-1.1 — Frequency Response and Frequency Bias Setting
Reliability Standard BAL-003-1.1 shall be retired immediately prior to the effective date of BAL-003-2 in the particular jurisdiction in which the revised standard is becoming effective.

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Unofficial Comment Form

Project 2017-01 Modifications to BAL-003-1.1

Do not use this form for submitting comments. Use the electronic form to submit informal comments on the **Project 2017-01 Modifications to BAL-003-1.1** project. The electronic form must be submitted by **8 p.m. Eastern, Thursday, January 17, 2019**.

Documents and information about this project are available on the project page. If you have questions, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

Background

Project 2017-01 Modifications to BAL-003-1.1
The purpose of this project is to review the issues identified in Phase I of the SAR and make corresponding modifications to BAL-003-1.1, as necessary.

Standard affected: BAL-003-1.1
The supporting documents for BAL-003-1.1 were developed using engineering judgment on the data collection and process needed to determine the Interconnection Frequency Response Obligation (IFRO), as well as the processing of raw data to determine compliance. Now that the Reliability Standard is in place and the data is available for analyses, minor errors in assumptions, as well as process inefficiencies have been identified. It was anticipated that as Frequency Response improves, the approaches embedded in the Reliability Standard for annual samples might need to be modified. In addition to fixing the inconsistencies identified in the Frequency Response Annual Analysis Report (FRAA), the drafting team is separating the administrative and procedural items and reassigning them to the Procedure for *ERO Support of Frequency Response and Frequency Bias Settings Standard*, subject to Electric Reliability Organization (ERO) and North American Electric Reliability Corporation (NERC) Operating Committee approval.

This formal comment period is seeking inputs into the standard drafting team's (SDT) proposed Phase I modifications to BAL-003-1.1:

- Replacing resource contingency criteria (RCC) by proposing a new methodology for determining the Resource Loss Protection Criteria (RLPC) that is consistent across all Interconnections, and is designed to maintain reliability for the respective Interconnections. The SDT recommends a process whereby the magnitude of the events to be protected against would be equal to the sum of two largest potential resource losses in that Interconnection;
- An IFRO methodology that makes changes only when technically justified and significant;
- To reduce risk to reliable operation due to a significant change in the Eastern Interconnection's (EI's) RLPC, structuring the reduction of the EI IFRO to decrease by no more than 10 percent annually until the full reduction (currently calculated to be 28 percent) is completed. This annual

reduction is dependent upon the annual evaluation of the Interconnection Frequency Response. If the annual evaluation determines a significant reduction in the Interconnection Frequency Response, then the IFRO will not be reduced until the factors leading to the degradation of the Interconnection Frequency Response are addressed or determined to not be a reliability concern; and

- Move items not related to entity compliance from BAL-003-1.1, Attachment A to the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document. This allows for issues not directly related to compliance to be addressed through an open NERC process that includes presentation for approval to the NERC Board of Trustees and informational filing with the Federal Energy Regulatory Commission (FERC), instead of the NERC Standards Development Process.

Please provide your responses to the questions listed below, along with any detailed comments.

Questions

1. The SDT proposes to replace Resource Contingency Criteria (RCC) with the Resource Loss Protection Criteria (RLPC). This criterion will be applied consistently across all Interconnections, and is designed to produce adequate reliability for each Interconnection. The RLPC determination methodology is detailed for this posting in the *Resource Loss Protection Criteria* Section of the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document and further in the *Resource Loss Protection Criteria* document. Is this methodology appropriate for determining the magnitude of the resource loss events that each Interconnection should protect against to assure an adequate level of reliability? If not, please provide an alternative proposal and any comments to the *Resource Loss Protection Criteria* document, which has been revised based on industry comment.

   ☐ Yes
   ☐ No

   Comments:

2. The SDT proposes fixing IFROs for a period that will continue until Phase 2 of the Project 2017-01 is completed. Do you agree with keeping IFROs as scheduled in Attachment A during the remainder of Project 2017-01? If you do not agree, please provide an alternative. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

   ☐ Yes
   ☐ No

   Comments:

3. The SDT is proposing to move items not related to entity compliance from BAL-003-1.1, Attachment A to the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document. Changes to this document will be subject to approval by the NERC Board of Trustees and informational filing to FERC. Do you agree that the SDT's proposed changes are appropriate? If not, please provide an alternative. Or, if you agree but have comments or

suggestions on the SDT's recommendation, please provide your explanation and suggested language.

☐ Yes
☐ No

Comments:

4. Please provide any additional comments for the SDT to consider that have not already been provided in the questions above.

Comments:

Violation Risk Factor and Violation Severity Level Justifications

Project 2017-01 Modifications to BAL-003-1.1

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard BAL-003-2. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements. Please note, the SDT is only proposing to change the VSL for Requirement R1. As a result, justification is only provided for the VSL for Requirement R1

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of a medium risk requirement is unlikely to lead to BES instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

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

FERC Guidelines for Violation Risk Factors

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

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

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

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard..

NERC Criteria for Violation Severity Levels

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

VSLs should be based on NERC's overarching criteria shown in the table below:

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

FERC Order of Violation Severity Levels

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

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

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

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

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

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

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

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

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

VRF Justification for BAL-003-1.1, Requirement R1
The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R1
This justification is provided on the following page.

VRF Justification for BAL-003-1.1, Requirement R2
The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R2
The VSL did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VRF Justification for BAL-003-1.1, Requirement R3
The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R3
The VSL did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VRF Justification for BAL-003-1.1, Requirement R4
The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R4
The VSL did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSLs for BAL-003-2, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority's (BA)s, or Frequency Response Sharing Group's (FRSG)s, Frequency Response Measure (FRM) was less negative than its Frequency Response Obligation (FRO) by more than 1% but by at most 15% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The BA's, or (FRSG)s, FRM was less negative than its FRO by more than 15% but by at most 30% or by more than 30 MW/0.1 Hz, whichever is the greater deviation from its FRO.	The BA's, or FRSGs, FRM was less negative than its FRO by more than 30% but by at most 45% or 45 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The BA's, or FRSG's, FRM was less negative than its FRO by more than 45% or by more than 45 MW/0.1 Hz, whichever is the greater deviation from its FRO.

VSL Justifications for BAL-003-2, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is not applicable since there was not a requirement mandating a certain level of Frequency Response prior to this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Proposed VSL's are not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the amount the calculated FRM is less negative than FRO.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Proposed VSL's do not expand on what is required. The VSL's assigned only consider results of the calculation required. Proposed VSL's are consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

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Frequency Response Standard Background Document

November, 2012

RELIABILITY | ACCOUNTABILITY



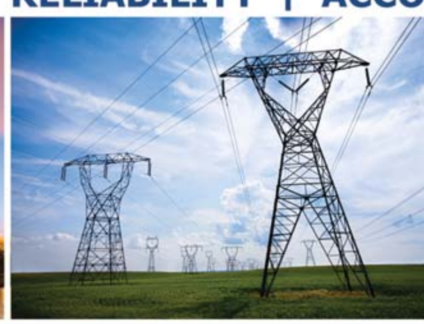


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Table of Contents

Introduction

This document provides background on the development, testing and implementation of BAL-003-1 - Frequency Response Standard ("FRS").[1] The intent is to explain the rationale and considerations for the Requirements of this standard and their associated compliance information. The document also provides good practices and tips for Balancing Authorities ("BAs") with regard to Frequency Response.

In Order No. 693, the Federal Energy Regulatory Commission ("FERC" or the "Commission") directed additional changes to BAL-003.[2] This document explains how compliance with those directives are met by BAL-003-1.

The original Standards Authorization Request ("SAR"), finalized on June 30, 2007, assumed there was adequate Frequency Response in all the North American Interconnections. The goal of the SAR was to update the Standard to make the measurement process of frequency response more objective and to provide this objective data to Planners and Operators for improved modeling. The updated models will improve understanding of the trends in Frequency Response to determine if reliability limits are being approached. The Standard would also lay the process groundwork for a transition to a performance-based Standard if reliability limits are approached.

This document will be periodically updated by the FRS Drafting Team ("FRSDT") until the Standard is approved. Once approved, this document will then be maintained and updated by the ERO and the NERC Resources Subcommittee to be used as a reference and training resource.

Background

This section discusses the different components of frequency control and the individual components of Primary Frequency Control also known as Frequency Response.

Frequency Control

Most system operators generally have a good understanding of frequency control and Bias Setting as outlined in the balancing standards and the references to them in the NERC Operating Manual. Frequency control can be divided into four overlapping windows of time as outlined below.

Primary Frequency Control (Frequency Response) – Actions provided by the Interconnection to arrest and stabilize frequency in response to frequency deviations.

[1] Unless otherwise designated herein, all capitalized terms shall have the meaning set forth in the Glossary of Terms Used in NERC Reliability Standards, available here: http://www.nerc.com/files/Glossary_of_Terms.pdf.

[2] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 368-375, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

Primary Control comes from automatic generator governor response (also known as speed regulation), load response (typically from motors), and other devices that provide an immediate response based on local (device-level) control systems.

Secondary Frequency Control – Actions provided by an individual BA or its Reserve Sharing Group to correct the resource – load unbalance that created the original frequency deviation, which will restore both Scheduled Frequency and Primary Frequency Response. Secondary Control comes from either manual or automated dispatch from a centralized control system.

Tertiary Frequency Control – Actions provided by Balancing Authorities on a balanced basis that are coordinated so there is a net zero effect on Area Control Error (ACE). Examples of Tertiary Control include dispatching generation to serve native load; economic dispatch; dispatching generation to affect Interchange; and re-dispatching generation. Tertiary Control actions are intended to replace Secondary Control Response by reconfiguring reserves.

Time Control includes small offsets to scheduled frequency to keep long term average frequency at 60 Hz.

Primary Frequency Control – Frequency Response

Primary Frequency Control, also known generally as **Frequency Response**, is the first stage of overall frequency control and is the response of resources and load to a locally sensed change in frequency in order to arrest that change in frequency. Frequency Response is automatic, not driven by any centralized system, and begins within seconds rather than minutes. Different resources, loads, and systems provide Frequency Response with different response times, based on current system conditions such as total resource/load and their respective mix.

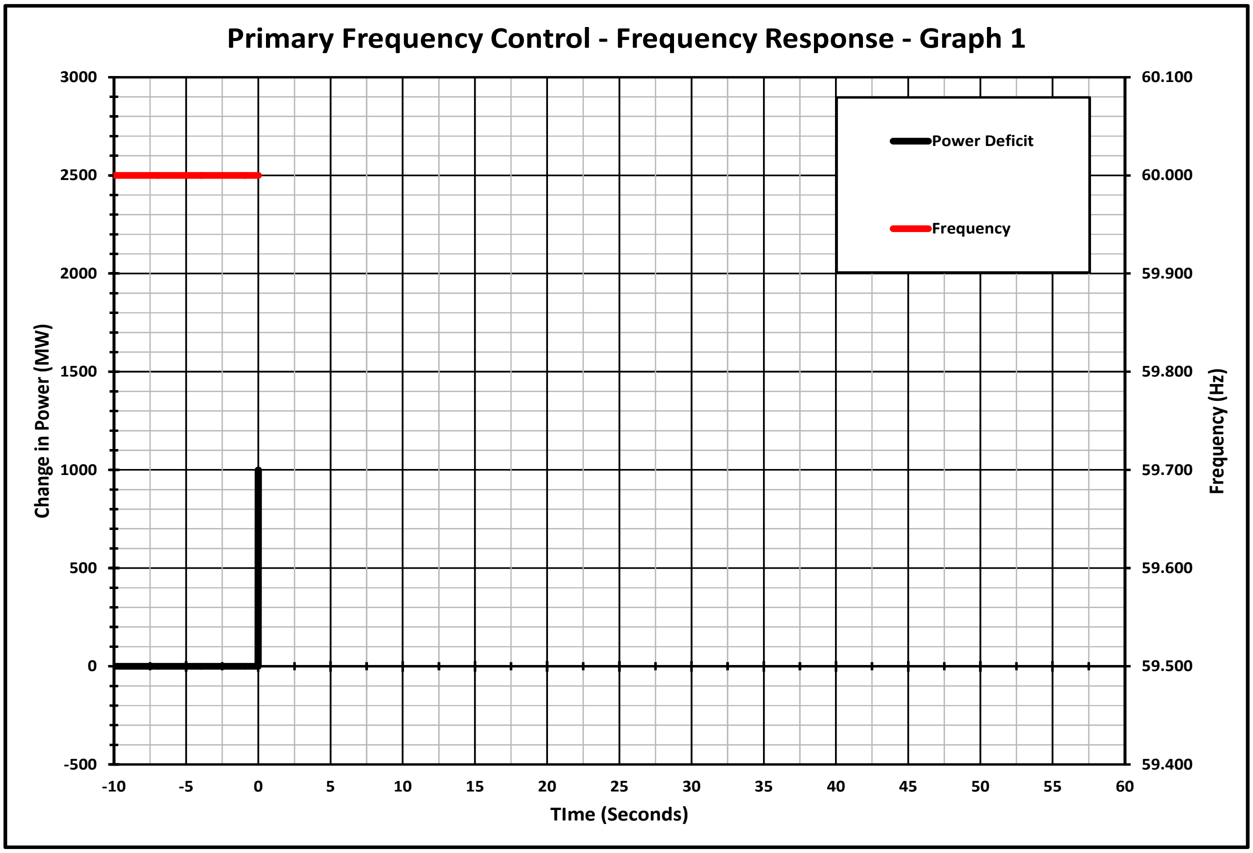
The proposed NERC Glossary of Terms defines **Frequency Response** as:

- (Equipment) The immediate and automatic reaction or response of power from a system or power from elements of the system to a change in locally sensed system frequency.
- (System) The sum of the change in demand, and the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).

As noted above, Frequency Response is the characteristic of load and generation within Balancing Authorities and Interconnections. It reacts or responds with changes in power to attempted changes in load-resource balance that result in changes to system frequency. Because the loss of a large generator is much more likely than a sudden loss of an equivalent amount of load, Frequency Response is typically discussed in the context of a loss of a large generator. Included within Frequency Response are many components of that response. Understanding Frequency Response and the FRS requires an understanding of each of these components and how they relate to each other.

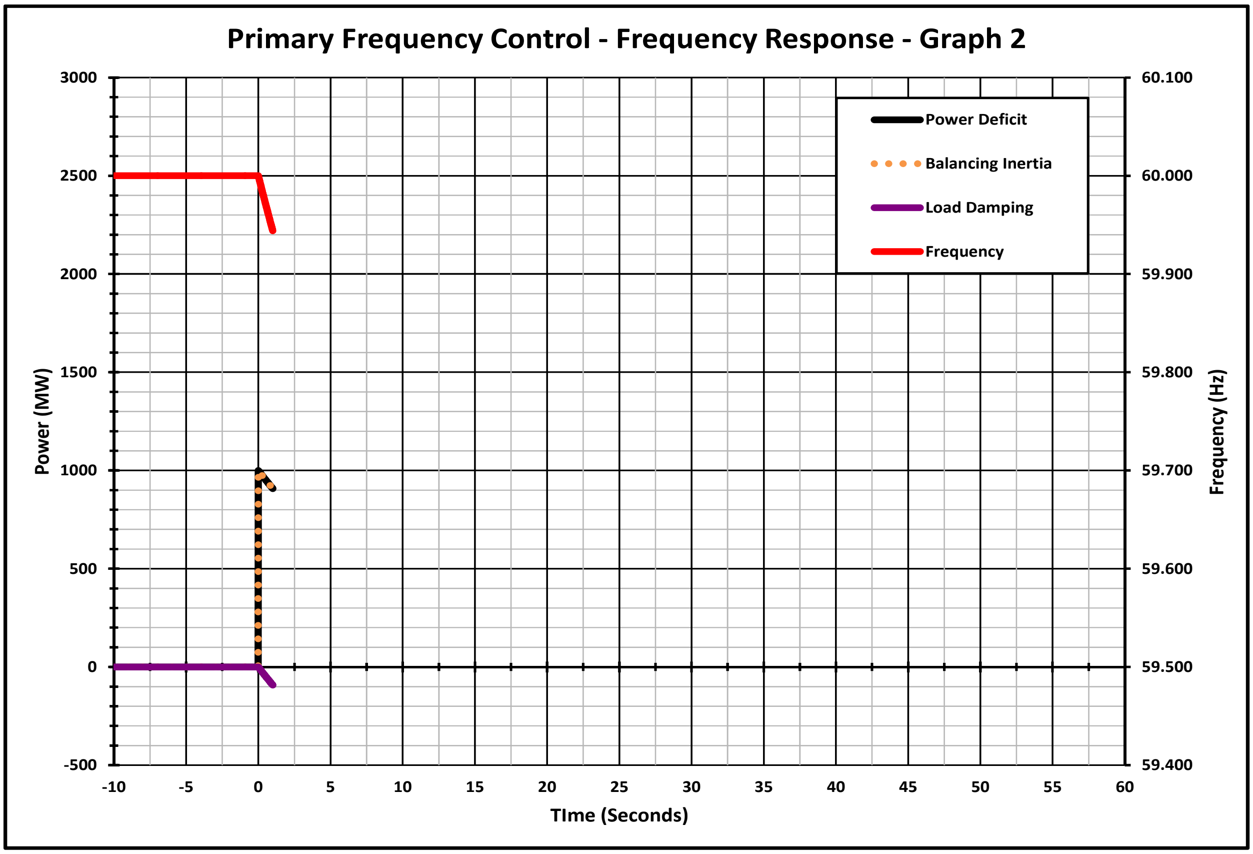
Frequency Response Illustration

The following simple example is presented to illustrate the components of Frequency Response in graphical form. It includes a series of seven graphs that illustrate the various components of Frequency Response and a brief discussion of each describing how these components react to attempted changes in the load-resource balance and resulting changes in system frequency. The illustration is based on an assumed Disturbance event of the sudden loss of 1000 MW of generation. Although a large event is used to illustrate the response components, even small frequently occurring events will result in similar reactions or responses. The magnitude of the event only affects the shape of the curves on the graph; it does not obviate the need for Frequency Response.



The first graph, Primary Frequency Control – Frequency Response – Graph 1, presents a sudden loss of generation of 1000 MW. The components are presented relative to time as shown on the horizontal Time axis in seconds. This simplified example assumes a Disturbance event of the sudden loss of generation resulting from a breaker trip that instantaneously removes 1000 MW of generation from the interconnection. This sudden loss is illustrated by the power deficit line shown in black using the MW scale on the left. Interconnection frequency is illustrated by the frequency line shown in red using the Hertz scale on the right. Since the Scheduled Frequency is normally 60 Hz, it is assumed that this is the frequency when the Disturbance event occurs.

Even though the generation has tripped and power injected by the generator has been removed from the interconnection, the loads continue to use the same amount of power. The "Law of Conservation of Energy"[3] requires that the 1000 MW must be supplied to the interconnection if energy balance is to be "conserved." This additional 1000 MW of power is produced by extracting kinetic energy that was stored in the rotating mass of all of the synchronized generators and motors on the interconnection – essentially using this equipment as a giant flywheel. The extracted energy supplies the "balancing inertia"[4] power required to maintain the power and energy balance on the interconnection. This balancing inertia power is produced by the generators' spinning inertial mass' resistance to the slowdown in speed of the rotating equipment on the interconnection that both provides the stored kinetic energy and reduces the frequency of the interconnection. This is illustrated in the second graph, Primary Frequency Control – Frequency Response – Graph 2, by the orange dots representing the balancing inertia power that exactly overlay and offset the power deficit.



As the frequency decreases, synchronized motors slow, as does the work they are providing, resulting in a decrease in load called "load damping." This load damping is the reason that the power deficit initially declines. Synchronously operated motors will contribute to load

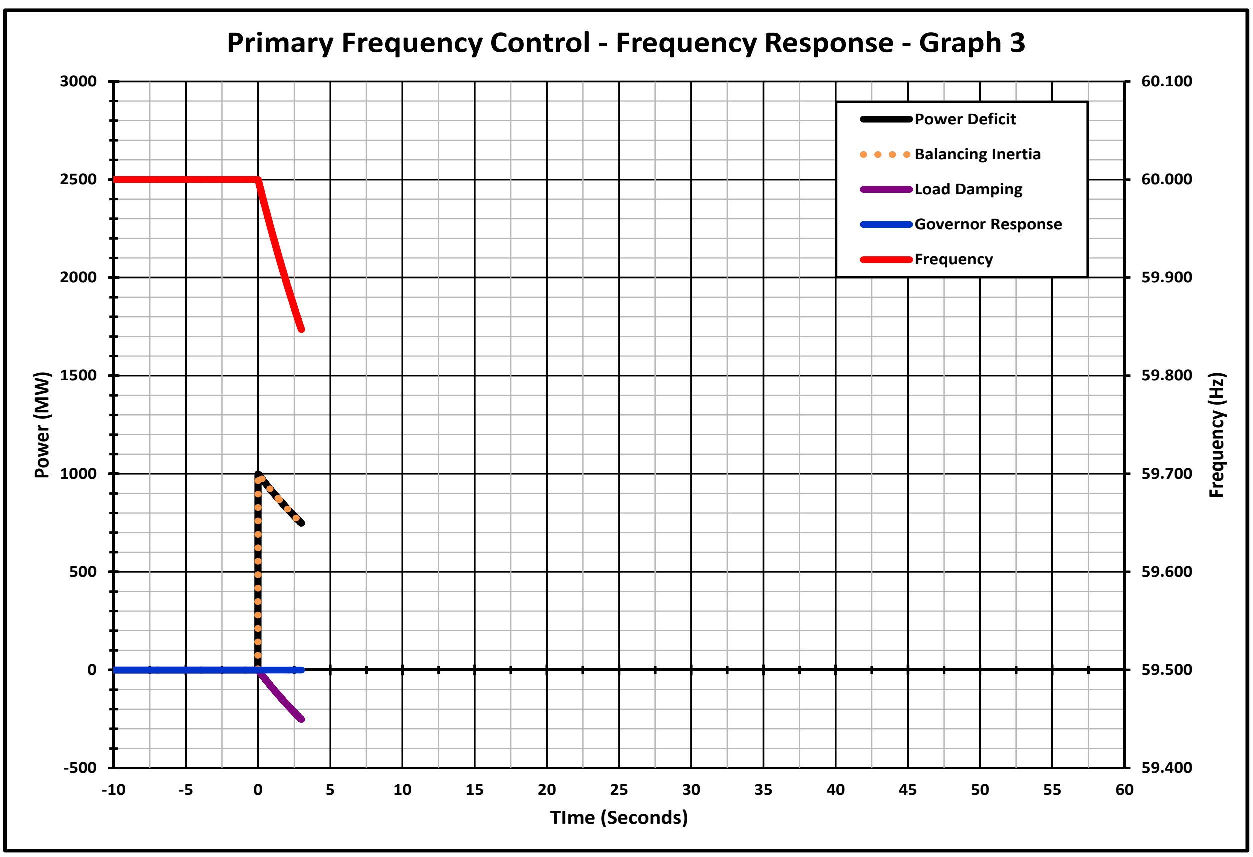
[3] The "Law of Conservation of Energy" is applied here in the form of power. If energy must be conserved, then power which is the first derivative of energy with respect to time, must also be conserved.

[4] The term "balancing Inertia" is coined here from the terms "inertial frequency response" and "balancing energy". Inertial frequency response is a common term used to describe the power supplied for this portion of the frequency response and balancing energy is a term used to describe the market energy supposedly purchased to restore energy balance.

damping. Variable speed drives that are decoupled from the interconnection frequency do not contribute to load damping. In general, any load that does not change with interconnection frequency including resistive load will not contribute to load damping or Frequency Response.

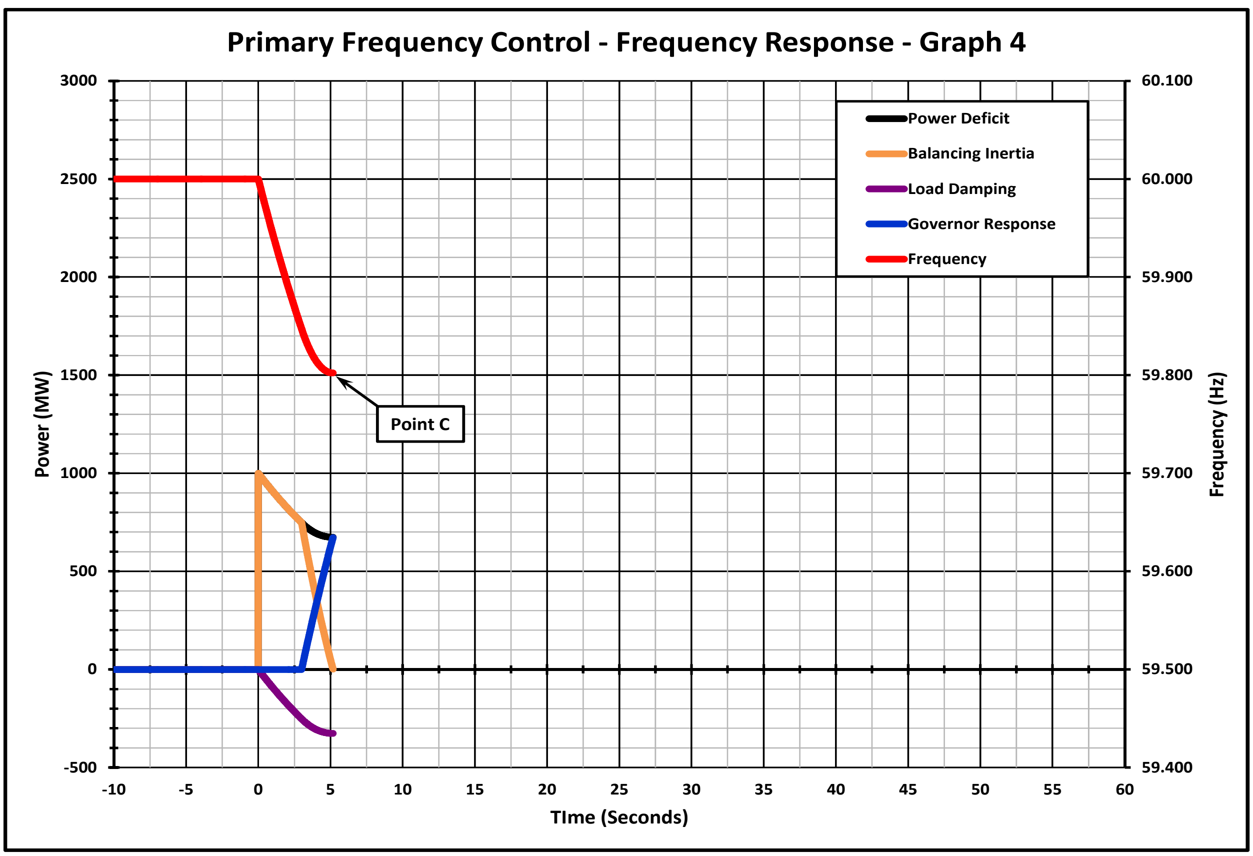
It is important to note that the power deficit equals exactly the balancing inertia, indicating that there is no power or energy imbalance at any time during this process. What is normally considered as "balancing power or energy" is actually power or energy required to correct the frequency error from scheduled frequency. Any apparent power or energy imbalance is corrected instantaneously by the balancing inertia power and energy extracted from the interconnection. Thus the balancing function is really a frequency control function described as a balancing function because ACE is calculated in MWs instead of Hertz, frequency error.

During the initial seconds of the Disturbance event, the governors have yet to respond to the frequency decline. This is illustrated with the Blue line on the third graph, Primary Frequency Control – Frequency Response – Graph 3, showing Governor Response. This time delay results from the time that it takes the controller to adjust the equipment and the time it takes the mass to flow from the source of the energy (main steam control valve for steam turbines, the combustor for gas turbines, or the gate valve for hydro turbines) to the turbine-generator blades where the power is converted to electrical energy.



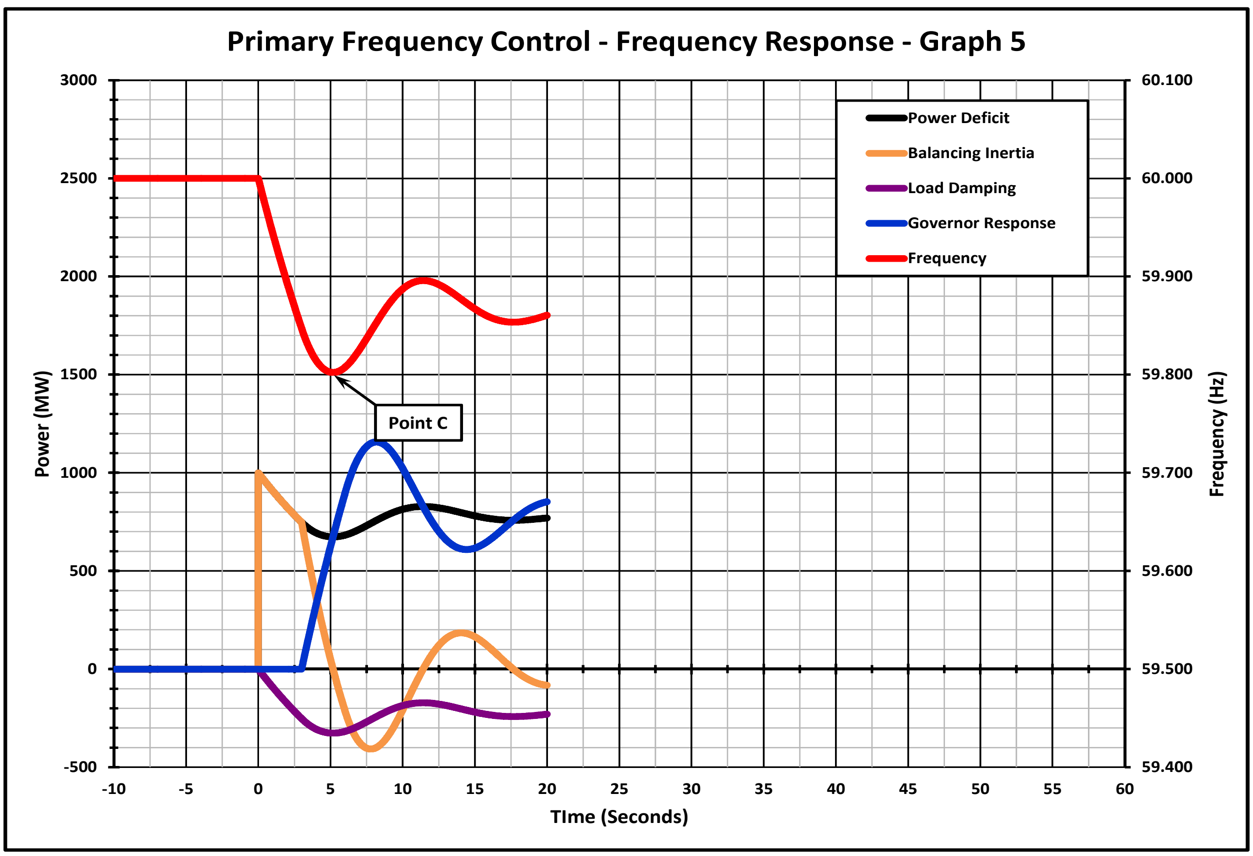
Note that the frequency continues to decline due to the ongoing extraction by balancing inertia power of energy from the rotating turbine-generators and synchronous motors on the interconnection. The reduction in load also continues as the effect of load damping continues to reduce the load while frequency declines. During this time delay (before the governor response begins) the balancing inertia limits the rate of change of frequency.

After a short time delay, the governor response begins to increase rapidly in response to the initial rapid decline in frequency, as illustrated on the fourth graph, Primary Frequency Control – Frequency Response – Graph 4. Governor response exactly offsets the power deficit at the point in time that the frequency decline is arrested. At this point in time, the balancing inertia has provided its contribution to reliability and its power contribution is reduced to zero as it is replaced by the governor response. If the time delay associated with the delivery of governor response is reduced, the amount of balancing inertia required to limit the change in frequency by the Disturbance event can also be reduced. This supports the conclusion that balancing inertia is required to manage the time delays associated with the delivery of Frequency Response. Not only is the rapid delivery of Frequency Response important, but the shortening of the time delay associated with its delivery is also important. Therefore, two important components of Frequency Response are 1) how long the time delay is before the initial delivery of response begins; and 2) how much of the response is delivered before the frequency change is arrested.

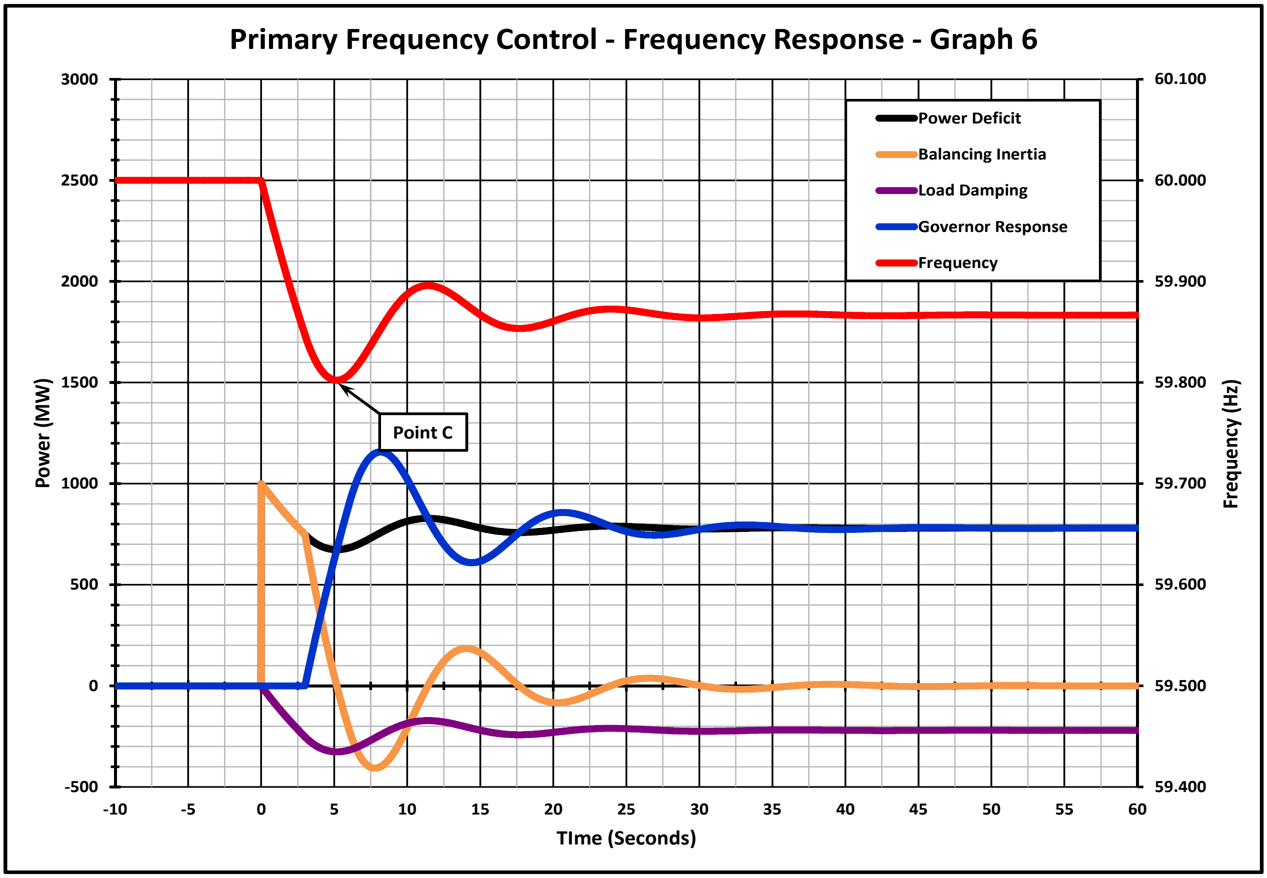


This point, at which the frequency is first arrested, is defined as “Point C” and Frequency Response calculated at this point is called the “**arrested frequency response**.” The arrested frequency is normally the minimum (maximum for load loss events) frequency that will be experienced during a Disturbance event. From a reliability perspective, this minimum frequency is the frequency that is of concern. Adequate reliability requires that frequency at the time frequency is arrested remain above the under-frequency relay settings so as not to trip these relays and the firm load interrupted by them. Frequency Response delivered after frequency is arrested at this minimum level provides less reliability value than Frequency Response delivered before Point C, but greater value than Secondary Frequency Control power and energy which is delivered minutes later.

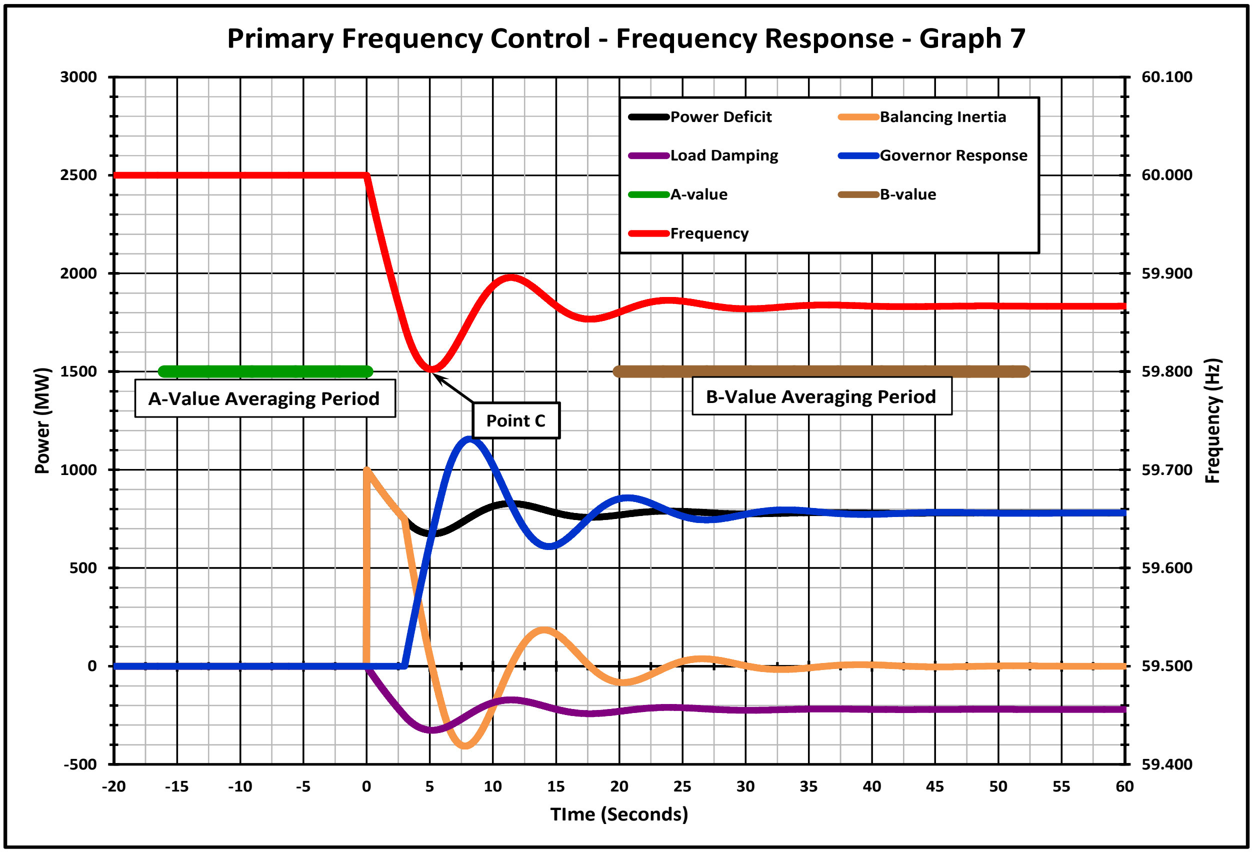
Once the frequency decline is arrested, the governors continue to respond because of the time delay associated with their Governor Response. This results in the frequency partially recovering from the minimum arrested value and results in an oscillating transient that follows the minimum frequency (arrested frequency) until power flows and frequency settle during the transient period that ends roughly 20 seconds after the Disturbance event. This post-disturbance transient period is included on the fifth illustrative graph, Primary Frequency Control – Frequency Response – Graph 5.



The total Disturbance event illustration is presented on the sixth graph, Primary Frequency Control – Frequency Response – Graph 6. Frequency and power contributions stabilize at the end of the transient period. Frequency Response calculated from data measured during this settled period is called the "Settled Frequency Response." The Settled Frequency Response is the best measure to use as an estimator for the "Frequency Bias Setting" discussed later.



The final Disturbance event illustration is presented on the seventh graph, Primary Frequency Control – Frequency Response – Graph 7. This graph shows the averaging periods used to estimate the pre-disturbance A-Value averaging period and the post-disturbance B-Value averaging period used to calculate the settled frequency response. A discussion of the measurement of Frequency Response immediately follows these graphs. That discussion includes consideration of the factors that affect the methods chosen to measure Frequency Response for implementation in a reliability standard.



Frequency Response Measurement (FRM)

The classic Frequency Response points A, C, and B, shown below in Fig. 1 Frequency Response Characteristic, are used for measurement as found in the Frequency Response Characteristic Survey Training Document within the NERC operating manual, found at http://www.nerc.com/files/opman_7-1-11.pdf. This traditional Frequency Response Measure has recently been more specifically termed "**settled frequency response**." This term has been used because it provides the best Frequency Response Measure to estimate the Frequency Bias Setting in Tie-line Bias Control based Automatic Generation Control Systems. However, the industry has recognized that there is considerable variability in measurement resulting from the selection of Point A and Point B in the traditional measure making the traditional measurement method unsuitable as the basis for an enforceable reliability standard in a real world setting of multiple Balancing Authority interconnections.

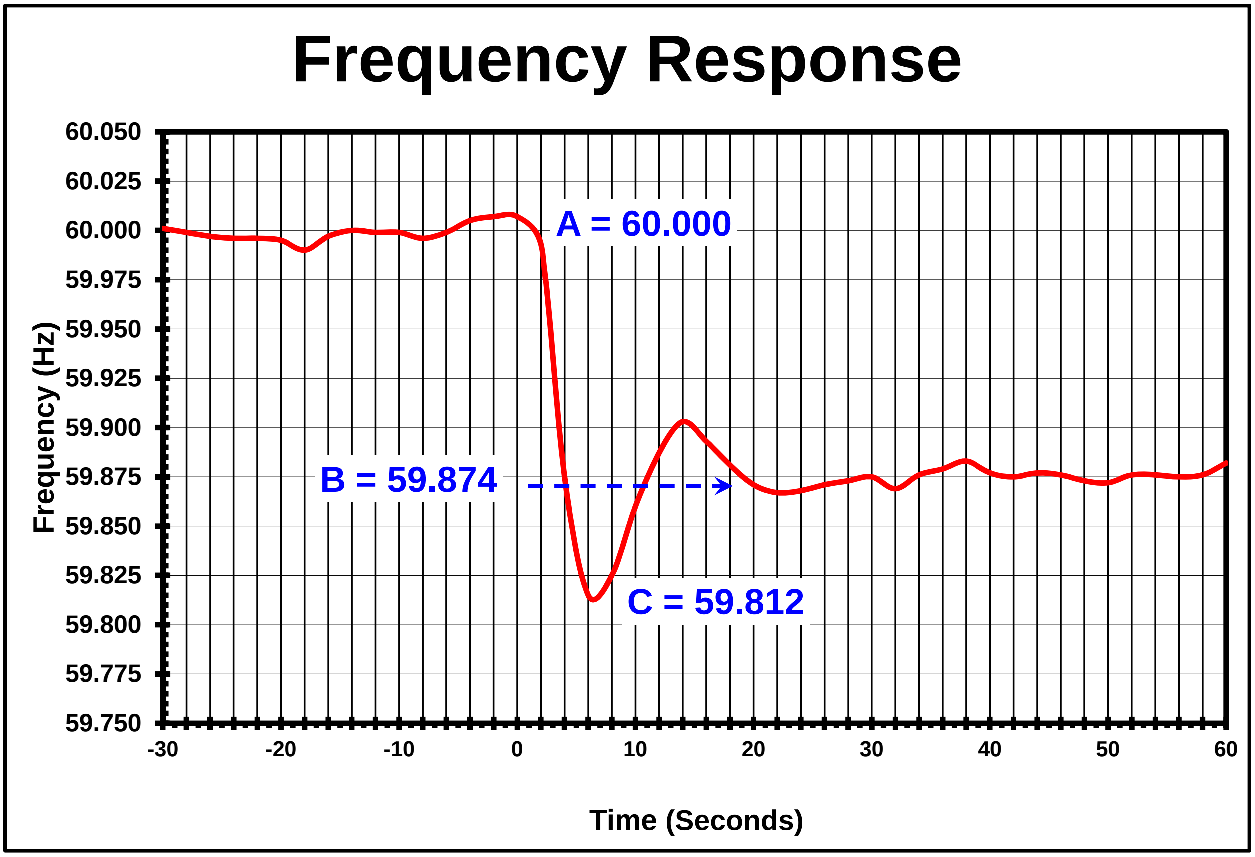


Figure 1. Frequency Response Characteristic

By contrast, measuring an Interconnection's settled frequency response is straightforward and fairly accurate. All that's needed to make the calculation is to know the size of a given contingency (MW), divide this value by the change in frequency and multiply the results by 10 since frequency response is expressed in MW/0.1Hz.

Measuring a BA's frequency response is more challenging. Prior to BAL-003-1, NERC's *Frequency Response Characteristic Survey Training Document* provided guidance to calculate Frequency Response. In short, it told the reader to identify the BA's interchange values "immediately before" and "immediately after" the Disturbance event and use the difference to calculate the MWs the BA deployed for the event. There are two challenges with this approach:

- Two people looking at the same data would come up with different values when assessing which exact points were immediately before and after the event.
- In practice, the actual response provided by the BA can change significantly in the window of time between point B and when secondary and tertiary control can assist in recovery.

Therefore, the measurement of settled frequency response has been standardized in a number of ways to limit the variability in measurement resulting from the poorly specified selection of Point A and Point B. It should be noted that t-0 has been defined as the first scan value that shows a deviation in frequency of some significance, usually approaching about 10 mHz. The goal is such that the first scan prior to t-0 was unaffected by the deviation and appropriate for one of the averaging points.

- The A-value averaging period of approximately the previous 16 seconds prior to t-0 was selected to allow for an averaging of at least 2 scans for entities utilizing 6 second scan rates. (All time average period references in this document are for 2 second scan rates unless noted otherwise.)
- The B-value averaging period of approximately (t+20 to t+52 seconds) was selected to attempt to obtain the average of the data after primary frequency response was deployed and the transient completed(settled), but before significance influence of secondary control. Multiple periods were considered for averaging the B-value:
  - 12 to 24 sec
  - 18 to 30 sec
  - 20 to 40 sec
  - 18 to 52 sec
  - 20 to 52 sec

  It is necessary for all BAs from an interconnection to use the same averaging periods to provide consistent results. In addition, the SDT decided that until more experience is gained, it is also desirable for all interconnections to use the same averaging periods to allow comparison between interconnections.

The methods presented in this document only address the values required to calculate the frequency response associated with the frequency change between the initial frequency, A-Value, and the settling frequency, B-Value. No reasonable or consistent calculations can be made relating to the arresting frequency, C-Value, using Energy Management System (EMS) scan rate data as long as 6-seconds or tie-line flow values associated with the minimum value of the frequency response characteristic (C-value) as measured at the BA level.

Both the calculation of the frequency at Point A and the frequency at Point B began with the assumption that a 6-second scan rate was the source of the data. Once the averaging periods for a 6-second scan rate were selected, the averaging periods for the other scan rates were selected to provide as much consistency as possible between BAs with different scan rates.

The Frequency at Point A was initially defined as the average of the two scans immediately prior to the frequency event. All other averaging periods were selected to be as consistent as possible with this 12 second average scan from the 6-second scan rate method. In addition, the "**actual net interchange immediately before Disturbance**" is defined as the average of the same scans as used for the Point A frequency average.

The Frequency at Point B was then selected to be an average as long as the average of 6-second scan data as possible that would not begin until most of the hydro governor response had been delivered and would end before significant Automatic Generation Control (AGC) recovery response had been initiated as indicated by a consistent frequency restoration slope. The "**actual net interchange immediately after Disturbance**" is defined as the average of the same scans as used for the Point B frequency average.

B Averaging Period Selection:

Experience from the Electric Reliability Council of Texas ("ERCOT") and the field trail on other interconnections indicated that the 12 to 24 second and 18 to 30 second averaging periods were not suitable because they did not provide the consistency in results that the other averaging periods provided, and that the remaining measuring periods do not provide significantly different results from each other. The team believed that this was observed because the transients were not complete in all of the samples using these averaging periods.

The 18 to 52 second and 20 to 52 second averaging periods were compared to each other, with the 20 to 52 second period providing more consistent values, believed to result from the incomplete transient in some of the 18 to 52 second samples.

This left a choice between the 20 to 40 second and the 20 to 52 second averaging periods. The team recognized that there would be more AGC response in the 20 to 52 second period, but the team also recognized that the 20 to 52 second period would provide a better measure of squelched response from outer loop control action. The 20 to 52 second period was selected because it would indicate squelched response from outer-loop control and provide incentive to reduce response withdrawal. The final selections for the data averaging periods used in FRS Form 1 are shown in the table below.

Definitions of Frequency Values for Frequency Response Calculation

Scan Rate	T 0 Scan	A Value (average)	B Value (average)
6-Seconds	Identify first significant change in frequency as the T 0 scan	Average of T-1 through T-2 scans	Average of T+4 through T+8 scans
5-Seconds		Average of T-1 through T-2 scans	Average of T+5 through T+10 scans
4-Seconds		Average of T-1 through T-3 scans	Average of T+6 through T+12 scans
3-Seconds		Average of T-1 through T-5 scans	Average of T+7 through T+17 scans
2-Seconds		Average of T-1 through T-8 scans	Average of T+10 through T+26 scans

Consistent measurement of Primary Frequency Response is achievable for a selected number of events and can produce representative frequency response values, provided an appropriate sample size is used in the analysis. Available research investigating the minimum sample size to provide consistent measurements of Frequency Response has shown that a minimum sample size of 20 events should be adequate.

Measurement of Primary Frequency Response on an individual resource or load basis requires analysis of energy amounts that are often small and difficult to measure using current methods. In addition, the number of an interconnection's resources and loads providing their response could be problematic when compiling results for multiple events.

Measurement of Primary Frequency Response on an interconnection (System) basis is straight forward provided that an accurate frequency metering source is available and the magnitude of the resource/load imbalance is known in MWs.

Measurement on a Balancing Authority basis can be a challenge, since the determination of change in MWs is determined by the change in the individual BA's metered tie lines. Summation of tie lines is accomplished by summing the results of values obtained by the digital scanning of meters at intervals up to six seconds, resulting in a non-coincidental summing of values. Until the technology to GPS time stamp tie line values at the meter and the summing of those values for coincidental times is in use throughout the industry, it is necessary to use averaging of values described above to obtain consistent results.

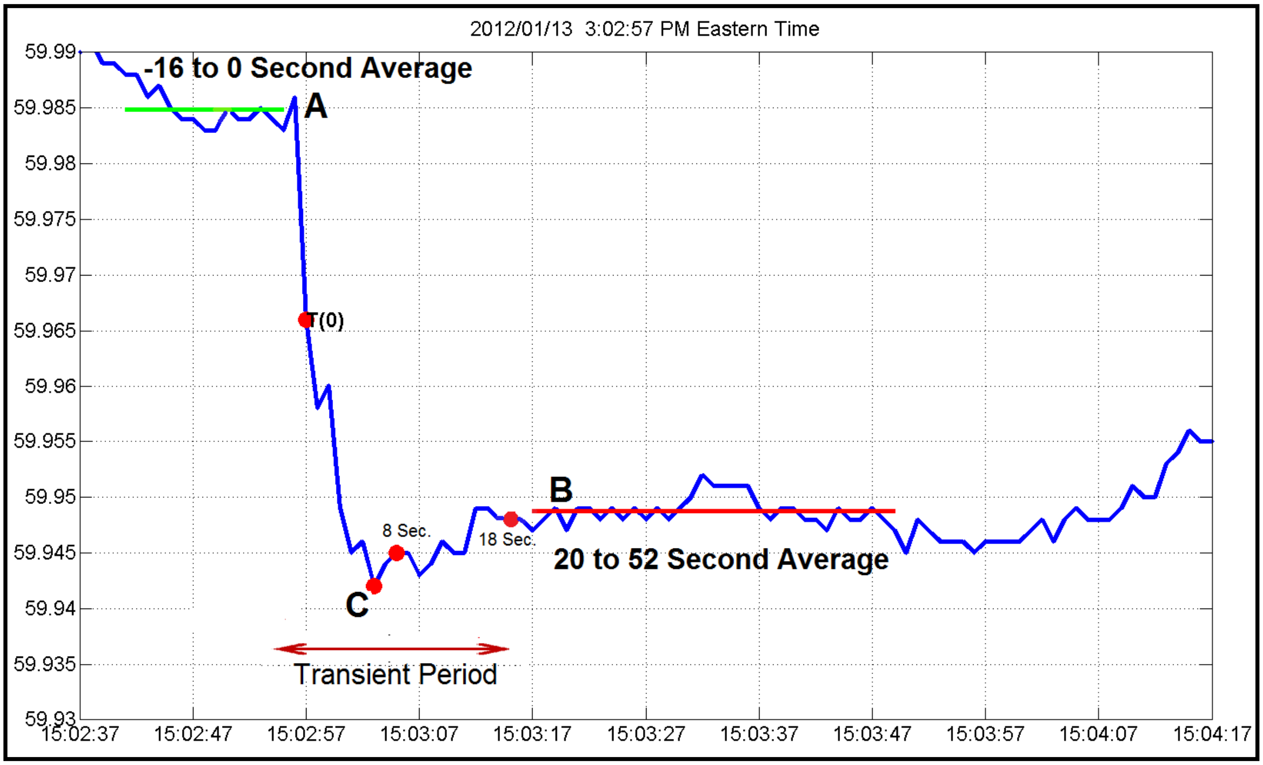


Figure 2. Frequency Response Measurement

The standardized measure is shown graphically in Fig. 2 Frequency Response Measurement with the averaging periods shown by the solid green and red lines on the graph. Since FERC directed a performance obligation for BAL-003-1, it is important to be more objective in the measurement process. The standardized calculation is available on FRS Form 2 for EMS scan rates of 2, 3, 4, 5, and 6 seconds at http://www.nerc.com/filez/standards/Frequency_Response.html.

Arrested Frequency Response

There is another measure of Frequency Response that is of interest when developing a Frequency Response estimate that not only will be used for estimating the Frequency Bias Setting, but will also be used to assure reliability by operating in a manner that will bound interconnection frequency and prevent the operation of Under-frequency Relays. This Frequency Response Measure has recently been named "**arrested frequency response.**" This Frequency Response is significantly affected by the inertial Frequency Response, the governor Frequency Response and the time delays associated with the delivery of governor Frequency

Response. It is calculated by using the change in frequency between the initial frequency, A, and the maximum frequency change during the event, C, instead of using the change between A and B. Arrested Frequency Response is the correct response for determining the minimum Frequency Response related to under-frequency relay operation and the support of interconnection reliability. This is because it can be used to provide a direct estimate of the maximum frequency deviation an interconnection will experience for an initial frequency and a given size event in MW. Unfortunately, arrested frequency response cannot currently be measured using the existing EMS-based measurement infrastructure. This limitation exists because the scan rates currently used in industry EMSs are incapable of measuring the net actual interchange at the same instant that the maximum frequency deviation is reached. Fortunately, the ratio of arrested frequency response and settled frequency response tends to be stable on an interconnection. This allows the settled frequency response value to be used as a surrogate for the arrested frequency response and implement a reasonable measure upon which to base a standard. One consequence of using the settled frequency response as a surrogate for the arrested frequency response is the inclusion of a large reliability margin in Interconnection Frequency Response Obligation to allow for the difference between the settled frequency response as measured and the arrested frequency response that indicates reliability.

As measurement infrastructure improves one might expect the Frequency Response Obligation to transition to a measurement based directly on the arrested frequency response while the Frequency Bias Setting will continue to be based on the settled frequency response. However, at this time, the measurement devices and methods in use do not support the necessary level of accuracy to estimate arrested frequency response contribution for an individual Balancing Authority.

Frequency Response Definition and Examples

Limitations of the measurement infrastructure determine the measurement methods recommended in this standard. The measurement limitations provide opportunities to improve the Frequency Response as measured in the standard without contributing to an improvement in Frequency Response that contributes to reliability. These definitions and examples provide a basis for determining which contributions to Frequency Response contribute the most to improved reliability. They also provide the basis for determining on a case by case basis whether the individual contributors to the Frequency Response Measure are also contributing to reliability.

General Frequency Response Characteristics

In the simplest case Frequency Response includes any automatic response to changes in local frequency. If that response works to decrease that change in frequency, it is beneficial to reliability. If that response works to increase that change in frequency, it is detrimental to reliability. However, this definition does not address the relative value of one response as compared to other responses that may be provided in a specific case.

There are numerous characteristics associated with the Frequency Response that affect the reliability value and economic value of the response. These characteristics include:

1. **Inertial** – the response is inertial or approximates inertial response

Inertial response provides power without delay that is proportional to the frequency and the change in frequency. Therefore, power provided by electronic control as synthetic Inertial response must be proportional to the frequency and change in frequency and be provided without a time delay.

2. **Immediate** – no unnecessary intentional time delays or reduction in the rate of response delivery
    a. time delay before the beginning of the response
    Turbines that convert heat or kinetic energy have time delays related to the time delay from the time that the control valves are moved to initiate the change in power and the time that the power is delivered to the generator. These times are usually associated with the time it takes a change in mass flow to travel from the control valve to the first blades of the turbine in the turbine generator.

    b. reduction in the rate of response delivery
    There are natural delays associated with the rate of response delivery that are related to the mass flow travel from the first turbine blades to the last turbine blades. In addition, some turbines have intentional delays designed into the control system to slow the rate of change in the delivery of the kinetic energy or fuel to the turbine to prevent the turbine or other equipment from being damaged, hydro turbines, or to prevent the turbine from tripping due to excessive rate of change, gas turbines.
3. **Proportional** – the amount of the total response is proportional to the frequency error
    a. No Deadband – the response is proportional across the entire frequency range
    b. Deadband – the response is only proportional outside of a defined deadband

4. **Bi-directional** – the response occurs to both increases and decreases in frequency

5. **Continuous** – there are no discontinuities in the delivery of the response (no step changes)

6. **Sustained** – the response is sustained until frequency is returned to schedule

Frequency Response Reliability Value
This section contains a more detailed discussion of the various characteristics of Frequency Response listed in the previous section. It also provides an indication of the relative value of these characteristics with respect to their contribution to reliability. Finally, it includes some examples of the described responses.

Inertial Response is provided from the stored energy in the rotating mass of the turbine-generators and synchronous motors on the interconnection. It limits the rate of change of frequency until sufficient Frequency Response can be supplied to arrest the change in frequency. Its reliability value increases as the time delay associated with the delivery of other Frequency Response on the interconnection increases. If those time delays are minimal, then the value of inertial response is low. If all time delays associated with the Frequency Response could be eliminated, then inertial response would have little value.

The reliability value of Inertial Response is the greatest on small interconnections because the size of the Disturbance events is larger relative to the inertia of the interconnection. Electronic controls have been developed to provide synthetic inertial response from the stored energy in asynchronous generators to supplement the natural inertial response. Some Type III & IV Wind Turbines have this capability. In addition, electronically controlled SCRs have been developed that can store energy in the electrical system and release this stored energy to supply synthetic inertial response when required.

Immediate Response is provided by load damping and because the time delays associated with its delivery are very short (related to the speed of electrical signal in the electrical system); load damping requires very little inertial response to limit arrested frequency effectively. Synthetic immediate response can also be supplied from loads because in many cases, there is no mass flow time delay associated with the load process providing the power and energy reduction. Therefore, loads can provide an immediate response with a higher reliability value than generators with time delays required by the physics of the turbine-generator.

Governor response has time delays associated with its delivery. Governor response provided with shorter time delays has a higher reliability value because those shorter time delays require less inertial response to arrest frequency. Governor response is provided by the turbine-generators on the interconnection. Time delays associated with governor response vary depending on the type of turbine-generator providing the response.

The longest time delays are usually associated with high head hydro turbine-generators that require long times from the governor action until the additional mass flow through the turbine. These units may also have the longest delivery time associated with the full delivery of response because of the timing designed into the governor response.[5]

Intermediate time delays are usually associated with steam turbine-generators. The response begins when the steam control valves are adjusted and the steam mass flows from the valves to the first high pressure turbine blades. The delivery times associated with the full delivery of response may require the steam to flow through high, intermediate and low pressure turbines including reheat flows before full power is delivered. These times are shorter than those of the hydro turbine-generators in general, but not as fast as the times associated with gas turbines.[6]

Gas turbines typically have the shortest time delays, because control is provided by injecting more or less fuel into the turbine combustor and adjusting the air control dampers. These control changes can be initiated rapidly and the mass flow has the shortest path to the turbine

[5] Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns – Final Report, IEEE, May 2007, pp. 1-6 – 1-9.

[6] Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns – Final Report, IEEE, May 2007, pp. 1-4 – 1-6.

blades. There may be timing limitations related to the rate of change in output of the gas turbine-generator to maintain flame stability in some cases slowing the rate of change.[7]

Synthetic Governor Response can be supplied by certain loads and storage systems. The immediacy of the response is normally limited only by the electronic controls used to activate the desired response. Synthetic response, when it can be supplied immediately without significant time delay, has a higher reliability value because it requires less inertial response to achieve smaller arrested frequency deviations.

Proportional Response indicates that the response provided is proportional in magnitude to the frequency error. Response deadbands cause a non-proportional response and reduce the value of the response with respect to reliability. Contrary to general consensus, deadbands do not reduce the amount of Frequency Response that must be provided, they only transfer the responsibility for providing that Frequency Response from one source on the interconnection to another. For a given response, the response with the smaller deadband has the greater reliability value. Therefore, deadbands should be set to the smallest value that supports overall reliable operation including the reliable operation of the generator.

Electronic controls have also been developed to provide synthetic governor response. When these controls are applied to certain loads or stored energy systems, they can be programmed to provide synthetic governor response similar to the proportional response of a turbine-generator governor. Governor response in generators is limited to a small percentage of the output of the generating unit, while synthetic governor response could be applied to much larger percentages of loads or storage devices providing such response.

Load damping provides a proportional response.

Continuous Response is response that has no discontinuous (step) changes in the frequency versus response curve. Step changes (Non-continuous Response) in the Governor Response curve can lead to frequency instabilities at frequencies near the changes. The ERCOT Interconnection observed this and has since prohibited the use of governor response characteristics incorporating step responses.

Step responses also occur with the implementation of load interruption using under-frequency or over-frequency relays.

Bi-directional Response is response that occurs in both directions, when the frequency is increasing and when the frequency is decreasing. A uni-directional response is a response that only occurs once when frequency is decreasing or when frequency is increasing.

Inertial response, governor response and load damping are all bi-directional responses. Certain loads are capable of providing proportional bi-directional response while others are only capable of providing non-proportional bi-directional response.

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[7] Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns – Final Report, IEEE, May 2007, pp. 1-16 – 1-19.

The ERCOT Load Resource program is a uni-directional response program. Loads are only tripped when frequency declines below a given set-point. When frequency is restored above that set-point, the loads must be manually reconnected. As a consequence, the Frequency Response only occurs once with declining frequency and does not oppose the increase in frequency after the initial decline. If there should be a frequency oscillation, the uni-directional response will not contribute to the opposition of a second frequency decline across the set-point during an oscillation event. Once a uni-directional response has occurred, it is unavailable for a second decline before reset.

Step or proportional responses implemented bi-directionally can lead to frequency instability when there is less continuous frequency response than the magnitude of the change in continuous response between the trip and reset frequencies in step, or the proportional response rate of change is greater than the underlying continuous response. A step bi-directional response will have the load reconnected as frequency recovers from the event thus opposing the increase in frequency during recovery, and also resetting the load response for the next frequency decline automatically. Bi-directional response obviously has a greater reliability value than uni-directional response.

Sustained Response is provided at its full value until frequency is restored to its scheduled value. On today's interconnections, few frequency responses are fully sustained until frequency has been restored to its scheduled value. On steam based turbine-generators, the steam pressure may drop after a time as the result of the additional steam flow from governor action. However, in general this has not been a problem because most responses are incomplete at the time that frequency has been initially arrested and the additional response has generally been sufficient to make up for more than the these unpreventable reductions in response. However, the intentional withdrawal of response before frequency has been restored to schedule can cause a decline in frequency beyond that which would be otherwise expected. This intentional withdrawal of response is highly detrimental to reliability. Therefore, it can be concluded in general that sustained response has a higher reliability value than un-sustained response.

On an interconnection, the withdrawal of response due to the loss of steam pressure on the steam units may be offset by the slower response of hydro turbine-generators. In these cases, the reliability of the combined response provides a greater reliability value than the individual response of each type. The steam turbine-generators provide a fast response that may be reduced, while the hydro turbine-generators provide a slower response, contributing less to the arresting response, offsetting any reduction by the steam turbine-generators to assure a sustained response.

Sustained Response must also be considered for any resource that has a limited duration associated with its response. The amount of stored energy available from a resource may limit its ability to sustain response for a duration of time necessary to support reliability.

Frequency Response Cost Factors

In every system of exchange there are two sides; the supply side and the demand side. The supply side provides the services used by the demand side. In the case of Frequency Response, the supply side includes all providers of Frequency Response and the demand side includes all participants that create the need for Frequency Response.

Frequency Response Costs – Supply Side

There are a number of factors that affect the cost of providing Frequency Response from resources. Since there is a cost associated with those factors, some method of appropriate compensation could be made available to those resources providing Frequency Response. Without compensation, providers of Frequency Response will be put in the position of incurring additional cost that can be avoided only by reducing or eliminating the response they provide. These costs are incurred independently of whether provided for in a formal Regional Transmission Organization/Independent System Operator (RTO/ISO) market or in a traditional BA subject to the FERC pro-forma tariffs.

It is the responsibility of the BA or the RTO/ISO to acquire the necessary amount of Frequency Response to support reliability in the most cost effective manner. This function is performed best when the suppliers are evaluated based on the value of the Frequency Response they provide and compensated appropriately for that Frequency Response. Suppliers provide Frequency Response when they are assured that they will receive fair compensation. Before considering how to perform this evaluation and compensation, the costs associated with providing Frequency Response should be understood and evaluated with respect to the level of reliability they offer.

Some cost factors that have been identified for providing Frequency Response include:

1. **Capacity Opportunity Cost** – the costs, including opportunity costs, associated with reserving capacity to provide Frequency Response. These costs are usually associated with the alternative use of the same capacity to provide energy or other ancillary services. There may also be capacity opportunity costs associated with the loss in average capacity by a load providing Frequency Response.
2. **Fuel Cost** – The cost of fuel used to provide the Frequency Response. The costs for fuel to provide Frequency Response can result in energy costs significantly different from the system marginal energy cost, both higher and lower. This is the case when Frequency Response is provided by resources that are not at the system marginal cost.
3. **Energy Efficiency Penalty Costs** – the costs associated with the loss in efficiency when the resource is operated in a mode that supports the delivery of Frequency Response. This cost is usually in the form of additional fuel use to provide the same amount of energy. An example is the difference between operating a steam turbine in valve control mode with an active governor and sliding pressure mode with valves wide open and no active governor control except for over-speed. This cost is incurred for all of the energy provided by the resource, not just the energy provided for Frequency Response. There may be additional energy costs associated with a load providing Frequency Response from loss in efficiency of their process when load is reduced.
4. **Capacity Efficiency Penalty Costs** – the costs associated with any reduction in capacity resulting from the loss of capacity associated with the loss in energy efficiency. When efficiency is lost, capacity may be lost at the same time because of limitations in the amount of input energy that can be provided to the resource.

5. **Maintenance Costs** – the operation of the resource in a manner necessary to provide Frequency Response may result in increases in the maintenance costs associated with the resource.
6. **Emissions Costs** – the additional costs incurred to manage any additional emissions that result when the resource is providing Frequency Response or stands ready to provide Frequency Response.

A good contract for the acquisition of Frequency Response from a resource will provide appropriate compensation to the resource for all of the costs the resource incurs to provide Frequency Response. It will also provide a method to evaluate the least cost mix of resources necessary to provide the minimum required Frequency Response for maintaining reliability. Finally, it will provide the least complex method of evaluation considering the complexity and efficiency of the acquisition process.

Frequency Response Costs – Demand Side

Not only are there costs associated with acquiring Frequency Response from the supplying resources, there are costs associated with the amount of Frequency Response that must be acquired and influenced by those participants that create the need for Frequency Response. If the costs of acquiring Frequency Response from the supply resources can be assigned to those parties that create the need for Frequency Response, there is the promise that the amount of Frequency Response required to maintain reliability can be minimized. The considerations are the same as those that are driving the development of “real time pricing” and “dynamic pricing”. If the costs are passed on to those contributing to the need for Frequency Response, incentives are created to reduce the need for Frequency Response making interconnection operations less expensive and more reliable. The problem is to balance both cost and complexity against reliability on both the supply side and the demand side.

Rationale by Requirement

Requirement 1

R1. Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or Balancing Authority that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation.

Background and Rationale

R1 is intended to meet the following primary objectives:

- Determine whether a Balancing Authority (BA) has sufficient Frequency Response for reliable operations.
- Provide the feeder information needed to calculate CPS limits and Frequency Bias Settings.

Primary Objective

With regard to the first objective, FRS Form 1 and the process in Attachment A provide the method for determining the Interconnections' necessary amount of Frequency Response and allocating it to the Balancing Authorities. The field trial for BAL-003-1 is testing an allocation methodology based on the amount of load and generation in the BA. This is to accommodate the wide spectrum of BAs from generation-only all the way to load-only.

Frequency Response Sharing Groups (FRSGs)

This standard proposes an entity called FRSG, which is defined as:

> *A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members.*

This standard allows Balancing Authorities to cooperatively form FRSGs as a means to jointly meet the FRS. There is no obligation to form or be a part of FRSGs. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of FERC's Order No. 693 directives.

FRSG performance may be calculated one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that sums each participant's individual event performance.

Frequency Response Obligation and Calculation

The basic Frequency Response Obligation is based on annual load and generation data reported in FERC Form 714 (where applicable, see below for non-jurisdictional entities) for the previous full calendar year. The basic allocation formula used by NERC is:

$$\mathrm{FRO_{BA}} = \mathrm{FRO_{Int}} \times \frac{\text{Annual Gen}_{\mathrm{BA}} + \text{Annual Load}_{\mathrm{BA}}}{\text{Annual Gen}_{\mathrm{Int}} + \text{Annual Load}_{\mathrm{Int}}}$$

Where:

- Annual Gen_{BA} is the annual "Net Generation (MWh)", FERC Form 714, line 13, column c of Part II - Schedule 3.
- Annual Load_{BA} is the annual "Net Energy for Load (MWh)", FERC Form 714, line 13, column e of Part II - Schedule 3.
- Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that interconnection.
- Annual Load_{Int} is the sum of all Annual Load_{BA} values reported in that interconnection.

Balancing Authorities that are not FERC jurisdictional should use the Form 714 Instructions to assemble and submit equivalent data. Until the BAL-003-1 process outlined in Attachment 1 is implemented, Balancing Authorities can approximate their FRO by multiplying their Interconnection's FRO by their share of Interconnection Bias. The data used for this calculation should be for the most recently filed Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which utilized data from 2011.

Balancing Authorities that merge or that transfer load or generation need to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation for the Interconnection remains the same and so that CPS limits can be adjusted.

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.

With regard to the second objective above (determining Frequency Bias Settings and CPS limits), Balancing Authorities have been asked to perform annual reviews of their Frequency Bias Settings by measuring their Frequency Response, dating back to Policy 1. This obligation was carried forward into BAL-003-01.b. While the associated training document provided useful information, it left many of the details to the judgment of the person doing the analysis. The FRS Form 1 and FRS Form 2 provide a consistent, objective process for calculating Frequency Response to develop an annual measure, the FRM.

The FRM will be computed from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event from a Balancing Authority that is used to calculate its Frequency Response, expressed in MW/0.1Hz". The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is basically the change of its net actual interchange on its tie lines with its adjacent Balancing Authorities divided by the change in interconnection frequency. (Some Balancing Authorities may choose to apply corrections to their net actual interchange values to account for factors such as nonconforming loads. FRS Form 1 shows the types of adjustments that are allowed.)

A standardized sampling interval of approximately 20 to 52 seconds will be used in the computation of SEFRD values. Microsoft Excel® spreadsheet interfaces for EMS scan rates of 2 through 6 seconds are provided to support the computation.

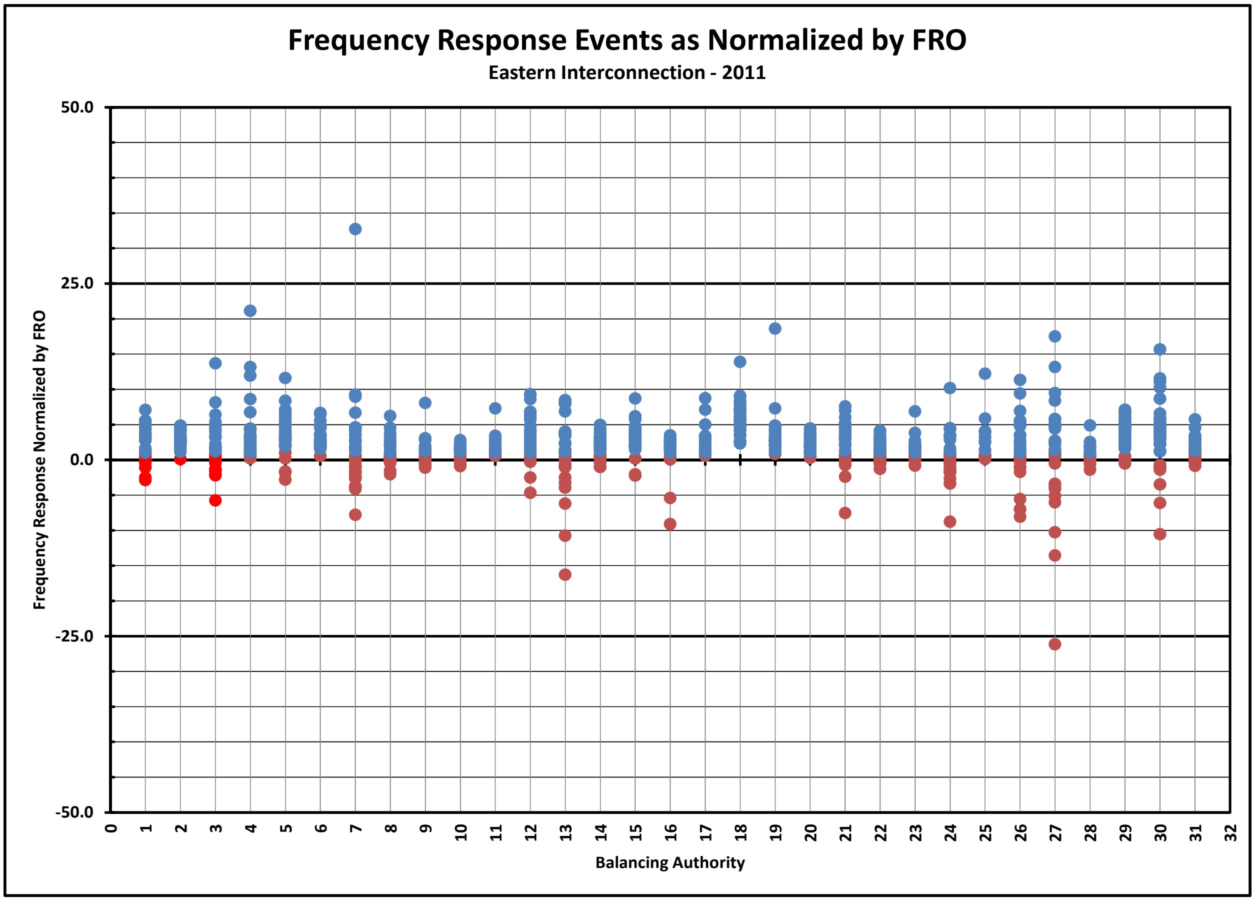
Single Event Frequency Response Data[8]

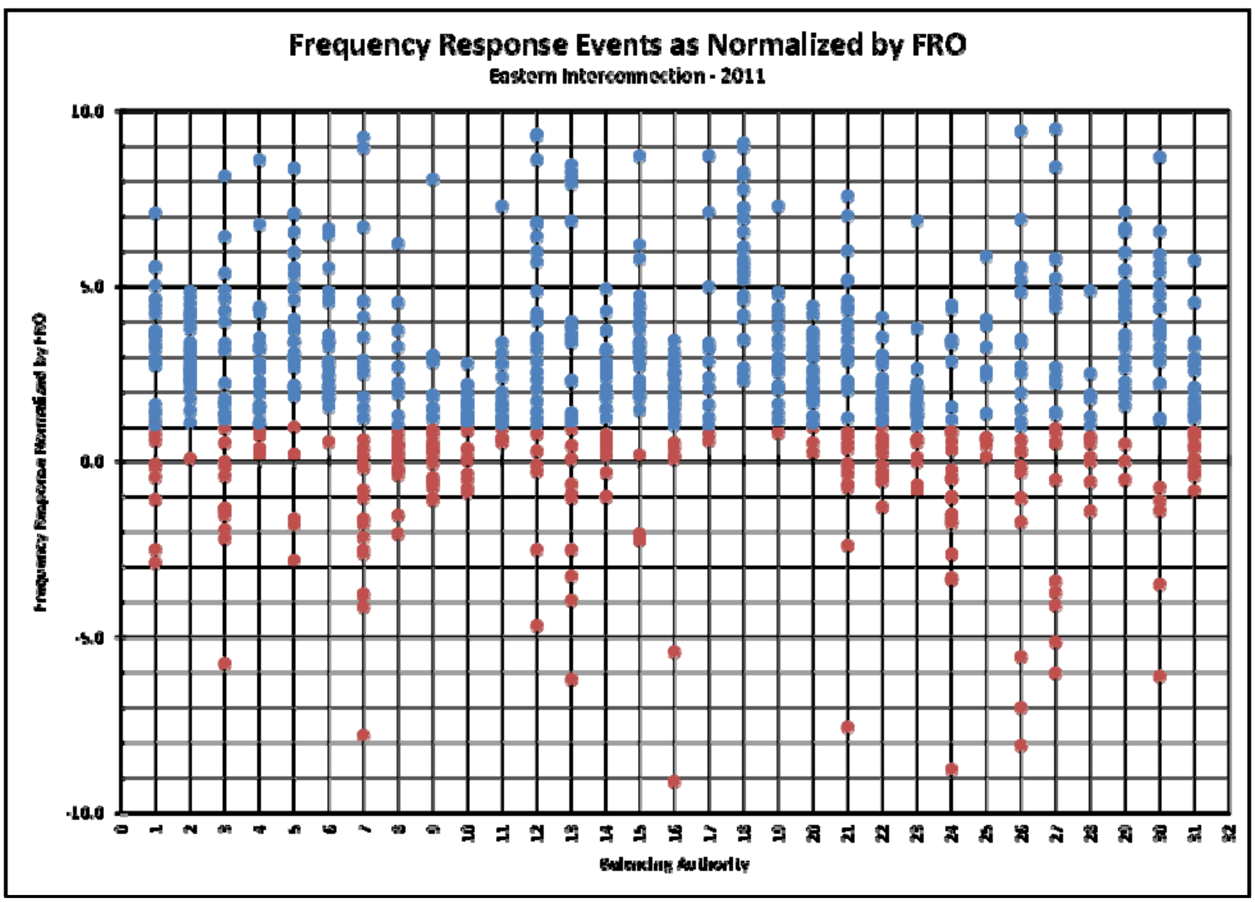
The use of a "single event measure" was considered early in the development of the FRS for compliance because a single event measure could be enforced for each event on the interconnection making compliance enforcement a simpler process. The variability of the measurement of Frequency Response for an individual BA for an individual Disturbance event was evaluated to determine its suitability for use as a compliance measure. The individual Disturbance events were normalized and plotted for each BA on the Eastern and Western Interconnections. This data was plotted with a dot representing each event. Events with a measured Frequency Response above the FRO were shown as blue dots and events with a measured Frequency Response below the FRO were shown as red dots. In order to show the full variability of the results the plots have been provided with two scales, a large scale to show all of the events and small scale to show the events closer to the FRO or a value of 1.0. This data is presented on four charts titled Frequency Response Events as Normalized by FRO.

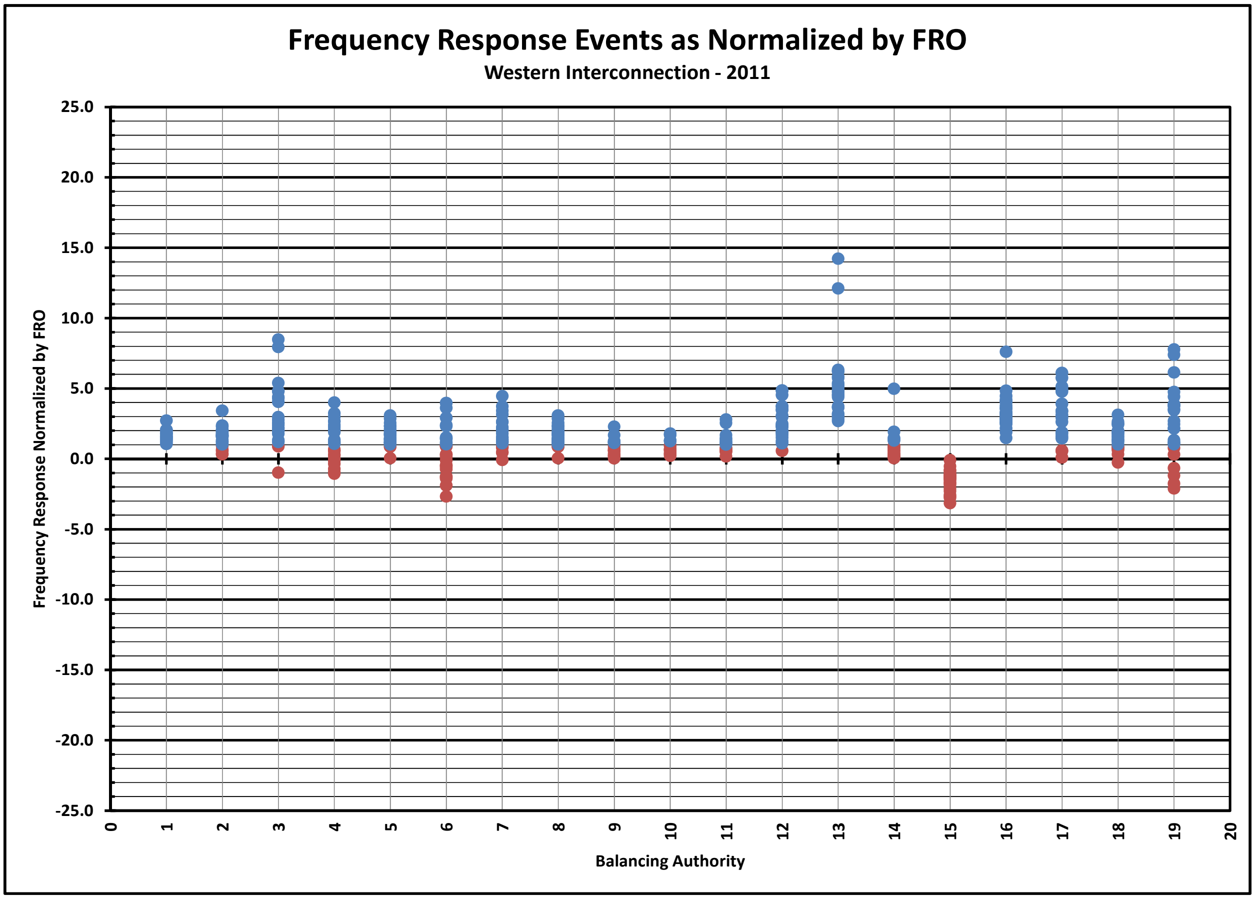
Analysis of this data indicates a single event based compliance measure is unsuitable for compliance evaluation when the data has the large degree of variability shown in these charts. Based on the field trial data provided, only 3 out of 19 BAs on the Western Interconnection would be compliant for all events with a standard based on a single event measure. Only 1 out of 31 BAs on the Eastern Interconnection would be compliant for all events with a standard based on a single event measure. The general consensus of the industry is that there is not a reliability issue with insufficient Frequency Response on any of the North American Interconnections at this time. Therefore, it is unreasonable to even consider a standard that would indicate over 90% of the BAs in North American to be non-compliant with respect to maintaining sufficient Frequency Response to maintain adequate reliability.

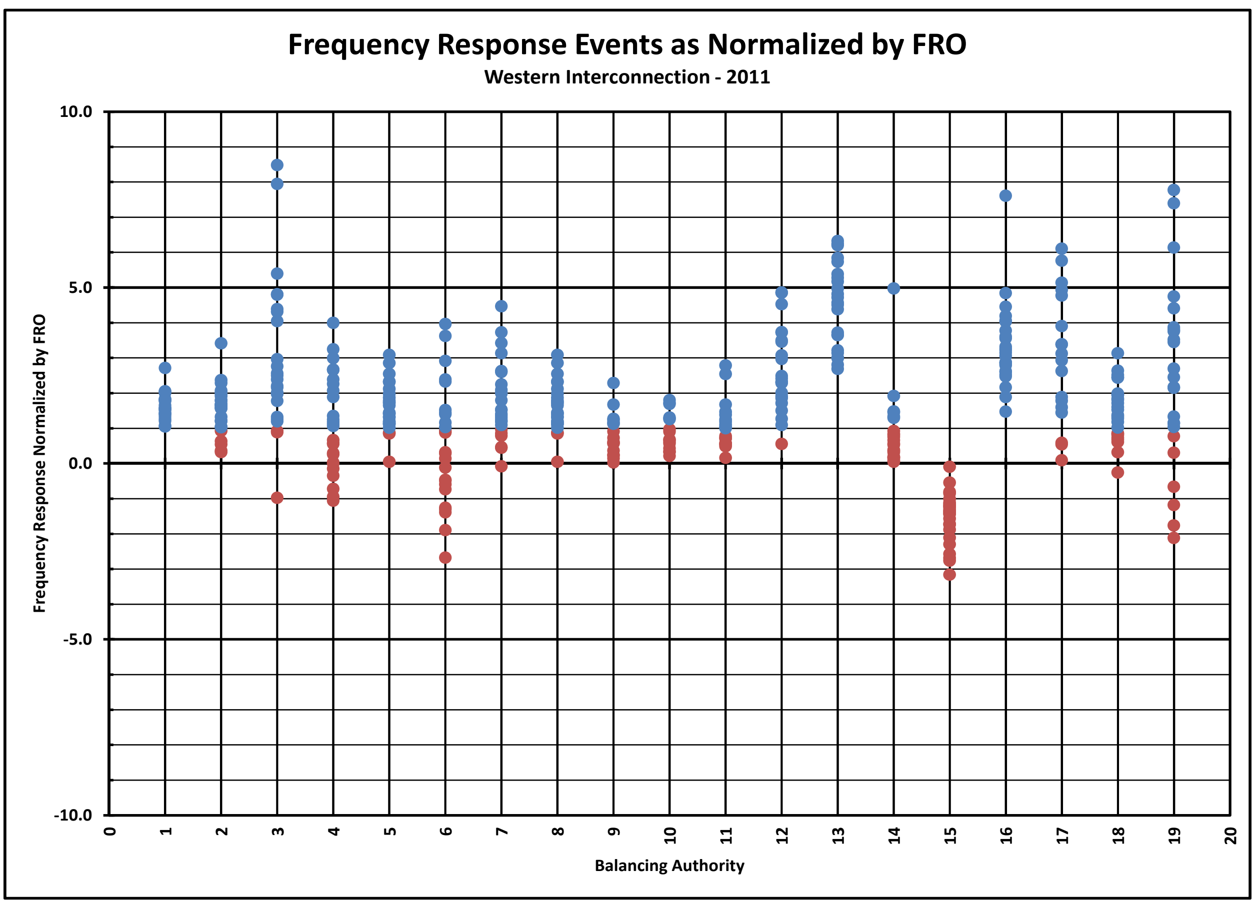
In an attempt to balance the workload of Balancing Authorities with the need for accuracy in the FRM, the standard will require at least 20 samples selected during the course of the year to compute the FRM. Research conducted by the FRSDT indicated that a Balancing Authority's FRM will converge to a reasonably stable value with at least 20 samples.

[8] Single Event Analysis based on results of Frequency Response Standard Field Trial Analysis, September 17, 2012.


Frequency Response Events as Normalized by FRO
Eastern Interconnection - 2011
Frequency Response Normalized by FRO
50.0
25.0
0.0
-25.0
-50.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32
Balancing Authority


Frequency Response Events as Normalized by FRO
Eastern Interconnection - 2011
10.0
5.0
0.0
-5.0
-10.0


Frequency Response Events as Normalized by FRO
Western Interconnection - 2011
Frequency Response Normalized by FRO
Balancing Authority
25.0
20.0
15.0
10.0
5.0
0.0
-5.0
-10.0
-15.0
-20.0
-25.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20


Frequency Response Events as Normalized by FRO
Western Interconnection - 2011
Frequency Response Normalized by FRO
Balancing Authority
10.0
5.0
0.0
-5.0
-10.0
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20

Sample Size
In order to support field trial evaluations of sample size, sampling intervals, and aggregation techniques, the FRSDT will be retrieving scan rate data from the Balancing Authorities for each SEFRD. Additional frequency events may also be requested for research purposes, though they will not be included in the FRM computation.

FERC Order No. 693 directed the ERO (at P 375) to define the number of Frequency Response surveys that were conducted each year and to define a necessary amount of Frequency Response. R1 addresses both of these directives:

- There is a single annual survey of at least 20 events each year.
- The FRM calculated on FRS Form 1 is compared by the ERO against the FRO determined 12 months earlier (when the last FRS Form 1 was submitted) to verify the Balancing Authority provided its share of Interconnection Frequency Response.

Median as the Standard's Measure of Balancing Authority Performance
The FRSDT evaluated different approaches for "averaging" individual event observations to compute a technically sound estimate of Frequency Response Measure. The MW contribution for a single BA in a multi-BA Interconnection is small compared to the minute to minute changes in load, interchange and generation. For example, a 3000 MW BA in the Eastern Interconnection may only be called on to contribute 10MW for the loss of a 1000MW. The 10 MW of governor and load response may easily be masked as a coincident change in load.

In general, statisticians use the median as the best measure of central tendency when a population has outliers. Two independent reviews by the FRSDT has shown the Median to be less influenced by noise in the measurement process and the team has chosen the median as the initial metric for calculating the BAs' Frequency Response Measure.

The FRSDT performed extensive empirical studies and engaged in lively discussions in an attempt to determine the best aggregation technique for a sample set size of at least 20 events. Mean, median, and linear regression techniques were used on a trial basis with the data that was available during the early phases of the effort.

A key characteristic of the "aggregation challenge" is related to the use of actual net interchange data for measuring frequency response. The tie line flow measurements are varying continuously due to other operational phenomena occurring concurrently with the provision of frequency response. (*See* Appendix 1 for details.) All samples have "noise" in them, as most operational personnel who have computed the frequency response of their BA can attest. What has also become apparent to the FRSDT is that while the majority of the frequency response samples have similar levels of noise in them, a few of the samples may have much larger errors in them than the others that result in unrepresentative results. And with the sample set size of interest, it is common to have unrepresentative errors in these few samples to be very large and asymmetric. For example, one BA's subject matter expert observed recently that 4 out of 31 samples had a much larger error contribution than the other 27 samples, and that 3 out of 4 of the very high error samples grossly underestimated the frequency response. The median value demonstrated greater resiliency to this data quality problem than the mean with this data set. (The median has also demonstrated superiority to linear regression in the presence of these described data quality problems in other analyses conducted by the FRSDT, but the linear regression showed better performance than the mean.)

The above can be demonstrated with a relatively simple example. Let's assume that a Balancing Authority's true frequency response has an average value of -200 MW/ .1 Hz. Let's also assume that this Balancing Authority installed "special" perfect metering on key loads and generators, so that we could know the true frequency response of each sample. And then we will compare them with that measured by typical tie line flow metering, with the kind of noise and error that occurs commonly and "not so commonly". Let's start with the following 4 samples having a common level of noise, with MW/ .1 Hz as the unit of measurement.

Perfect measurement	Noise	Samples from tie lines
-190	-30	-220
-210	-20	-230
-220	10	-210
-180	20	-160
-200	Mean	-205
-200	Median	-215

Now let's add a fifth sample, which is highly contaminated with noise and error that grossly underestimates frequency response.

Perfect measurement	Noise	Samples from tie lines
-190	-30	-220
-210	-20	-230
-220	10	-210
-180	20	-160
-200	250	+50
-200	Mean	-154
-200	Median	-210

It is clear from the above simplistic example that the mean drops by about 25% while the median is affected minimally by the single highly contaminated value.

Based on the analyses performed thus far, the FRSDT believes that the median's superior resiliency to this type of data quality problem makes it the best aggregation technique at this time. However, the FRSDT sees merit and promise in future research with sample filtering combined with a technique such as linear regression.

When compared with the mean, linear regression shows superior performance with respect to the elimination of noise because the measured data is weighted by the size of the frequency change associated with the event. Since the noise is independent from frequency change, the greater weighting on larger events provides a superior technique for reducing the effect of noise on the results.

However, linear regression does not provide a better method when dealing with a few samples with large magnitudes of noise and unrepresentative error. There are only two alternatives to improve over the use of median when dealing with these larger unrepresentative errors:

1. Increase the sample size, or
2. Actively eliminate outliers due to unrepresentative error.

Unfortunately, the first alternative, increasing the sample size is not available because significantly more sample events are not available within the measurement time period of one year. Linear regression techniques are being investigated that have an active outlier elimination algorithm that would eliminate data that lie outside ranges of the 96th percentile and 99th percentile, for example.

Still, the use of linear regression has value in the context of this standard. The NERC Resources Subcommittee will use linear regression to evaluate Interconnection frequency response, particularly to evaluate trends, seasonal impacts, time of day influences, etc. The Good Practices and Tools section of this document outlines how a BA can use linear regression to develop a predictive tool for its operators.

Additional discussion on this topic is contained in "Appendix 1 – Data Quality Concerns Related to the Use of Actual Net Interchange Value" of this document.

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. A brief summary of the FRSDT majority consensus on the basis of each evaluation criterion is provided below.

- Provides two dimensional measurement – The FRSDT agrees that the two dimensional concept is a useful way to perceive frequency response characteristics, and that it may be useful for potential future modeling activities. Better data quality would increase support for such future efforts, and the use of the median for initial compliance evaluations within BAL-003-1 should not hinder any such effort. The FRSDT perceived this as a mild advantage for linear regression.
- Represents nonlinear characteristics – With considerations similar to those applied to the previous criterion, the FRSDT perceived this as a mild advantage for linear regression.
- Provides a single best estimator – The FRSDT gave minimal importance to the characteristic of the median averaging the middle values when used with an even number of samples.
- Is part of a linear system - With considerations similar to those applied to the first two criteria, the FRSDT perceived this as a mild advantage for linear regression (particularly in the modeling area.)
- Represents bimodal distributions – The FRSDT gave minimal weight of this criterion, as a change in Balancing Authority footprint does not seem to be addressed adequately by any aggregation technique.
- Quality statistics available – The FRSDT perceived this as a mild advantage for linear regression in that the statistics would be coupled directly to the compliance evaluation. The FRSDT also included this criterion as part of the modeling advantages cited above.

The FRSDT supports collecting data and performing quality statistical analysis. If it is determined that the use of the median, as opposed to a mean or linear regression aggregation, is yielding undesirable consequences, the FRSDT recommends that other aggregation techniques be re-evaluated at that time.

- Reducing influence of noise - This is the dominant concern of the FRSDT, and it perceives the median to have a major advantage over linear regression in addressing noise in the change in actual net interchange calculation. The FRSDT bases this judgment on: prior FRSDT studies that have shown that the median produces more stable results; the data used in the NERC Frequency Response Initiative document exhibits large quantities of noise; prior efforts of FRSDT members in performing frequency response sampling for their own Balancing Authorities over many years; and similar observations of noise in the CERTS frequency Monitoring Application. The FRSDT has serious concerns that the influence of noise has a greater tendency to yield a “false positive” compliance violation with linear regression than with the median. Also, limited studies performed by the FRSDT indicates the possibility that the resultant frequency response measure would yield more measurement variation across years with linear regression versus the median while the actual Balancing Authority performance remains unchanged.
- Reducing the influence of outliers – This is related to the previous criterion. The FRSDT recognizes four main sources of noise: concurrent operating phenomena (described elsewhere in this document), transient tie line flows for nearby contingencies, data acquisition time skew in tie line data measurements, and time skew and data compression issues in archiving techniques and tools such as PI. Some outliers may be caused in part by true variation in the actual frequency response, and it is desirable to include those in the frequency response measure. The FRSDT supports efforts in the near future to distinguish between outliers caused by noise versus true frequency response, and progress in this area may make it feasible and desirable to replace the median with linear regression, or some other validated technique. The FRSDT does note that this is a substantial undertaking, and it would require substantial input from a sufficient number of experts to help distinguish noise from true frequency response.
- Easy to calculate – The FRSDT perceives this to be a minor to moderate advantage for the median. However, more complex (but reasonably so) techniques would receive more support if clear progress can be made in noise elimination.
- Familiar indicator – The FRSDT perceives this to be a minor to moderate advantage for the median. However, more complex (but reasonably so) techniques would receive more support if clear progress can be made as a result of noise elimination.
- Currently used as a measure in BAL-003 – The present standard refers to an average and does not provide specific guidance on the computation of that average, but the FRSDT puts minimal weight on this evaluation criterion.

In summary, the FRSDT perceives an approximate balance between the modeling advantage for linear regression and the simplicity advantage of the median. However, the clear determinant in endorsing the use of the median is the data quality issue related to concurrent operational phenomena, transient tie line flows, and data acquisition and archiving limitations.

FERC Order No. 693 also directed the Standard (at P 375) to identify methods for Balancing Authorities to obtain Frequency Response. Requirement R1 allows Balancing Authorities to participate in Frequency Response Sharing Groups (FRSGs) to provide or obtain Frequency Response. These may be the same FRSGs that cooperate for BAL-002-0 or may be FRSGs that form for the purposes of BAL-003-1.

If BAs participate as an FRSG for BAL-003-1, compliance is based on the sum of the participants' performance.

Two other ways that BAs could obtain Frequency Response are through Supplemental Service or Overlap Regulation Service:

- No special action is needed if a BA provides or receives supplemental regulation. If the regulation occurs via Pseudo Tie, the transfer occurs automatically as part of Net Actual Interchange (NIA) and in response to information transferred from recipient to provider.
- If a BA provides overlap regulation, its FRS Form 1 will include the Frequency Bias setting as well as peak load and generation of the combined Balancing Authority Areas. The FRM event data will be calculated on the sum of the provider's and recipient's performance.

In the Violation Severity Levels for Requirement R1, the impact of a BA not having enough frequency response depends on two factors:

- Does the Interconnection have sufficient response?
- How short is the BA in providing its FRO?

The VSL takes these factors into account. While the VSLs look different than some other standards, an explanation would be helpful.

VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plane as single-BA Interconnections.

Consider a small BA whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response, because this would treat multi-BA Interconnections more harshly than single BA Interconnections on a significant scale.

The "Lower" and "Medium" VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively.

Requirement 2

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 in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO.

Background and Rationale

Attachment A of the Standard discusses the process the ERO will follow to validate the BA's FRS Form 1 data and publish the official Frequency Bias Settings. Historically, it has taken multiple rounds of validation and outreach to confirm each BA's data due to transcription errors, misunderstanding of instructions, and other issues. While BAs historically submit Bias Setting data by January 1, it often takes one or more months to complete the process.

The target is to have BAs submit their data by January 10. The BAs are given 30 days to assemble their data since the BAs are dependent on the ERO to provide them with FRS Form 1, and there may be process delays in distributing the forms since they rely on identification of frequency events through November 30 of the preceding year.

Frequency Bias Settings generally change little from year to year. Given the fact that BAs can encounter staffing or EMS change issues coincident with the date the ERO sets for new Frequency Bias Setting implementation, the standard provides a 24 hour window on each side of the target date.

To recap the annual process:

1. The ERO posts the official list of frequency events to be used for this Standard in early December. The FRS Form 1 for each Interconnection will be posted shortly thereafter.

2. The Balancing Authority submits its revised annual Frequency Bias Setting value to NERC by January 10.

3. The ERO and the Resources Subcommittee validate Frequency Bias Setting values, perform error checking, and calculate, validate, and update CPS2 L10 values. This data collection and validation process can take as long as two months.

4. Once the L10 and Frequency Bias Setting values are validated, The ERO posts the values for the upcoming year and also informs the Balancing Authorities of the date on which to implement revised Frequency Bias Setting values. Implementation typically would be on or about March 1st of each year.

BAL-003-0.1b standard requires a minimum Frequency Bias Setting equal in absolute value to one percent of the Balancing Authority's estimated yearly peak demand (or maximum generation level if native load is not served). For most Balancing Authorities this calculated amount of Frequency Bias is significantly greater in absolute value than their actual Frequency Response characteristic (which represents an over-bias condition) resulting in over-control since a larger magnitude response is realized. This is especially true in the Eastern Interconnection where this condition requires excessive secondary frequency control response which degrades overall system performance and increases operating cost as compared to requiring an appropriate balance of primary and secondary frequency control response.

Balancing Authorities were given a minimum Frequency Bias Setting obligation because there had never been a mandatory Frequency Response Obligation. This historic "one percent of peak per 0.1Hz" obligation, dating back to NERC's predecessor, NAPSIC, was intended to ensure all BAs provide some support to Interconnection frequency.

The ideal system control state exists when the Frequency Bias Setting of the Balancing Authority exactly matches the actual Frequency Response characteristic of the Balancing Authority. If this is not achievable, over-bias is significantly better from a control perspective than under-bias with the caveat that Frequency Bias is set relatively close in magnitude to the Balancing Authority actual Frequency Response characteristic. Setting the Frequency Bias to better approximate the Balancing Authority natural Frequency Response characteristic will improve the quality and accuracy of ACE control, CPS & DCS and general AGC System control response. This is the technical basis for recommending an adjustment to the long standing "1% of peak/0.1Hz" Frequency Bias Setting. The Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard is intended to bring the Balancing Authorities' Frequency Bias Setting closer to their natural Frequency Response. Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard balances the following objectives:

- Bring the Frequency Bias Setting and Frequency Response closer together.
- Allow time to analyze impact on other Standards (CPS, BAAL and to a lesser extent DCS) by adjustments in the minimum Frequency Bias Setting, by accommodating only minor adjustments.
- Do not allow the Frequency Bias Setting minimum to drop below natural Frequency Response, because under-biasing could affect an Interconnection adversely.

Additional flexibility has been added to the Frequency Bias Setting based on the actual Frequency Response (FRM) by allowing the Frequency Bias Setting to have a value in the range from 100% of FRM to 125% of FRM. This change has been included for the following reasons:

- When the new standardized measurement method is applied to BAs with a Frequency Response close to the interconnection minimum response, the requirement to use FRM is as likely to result in a Frequency Bias Setting below the actual response as it is to result in a response above the actual response. From a reliability perspective, it is always better to have a Frequency Bias Setting slightly above the actual Frequency Response.

- As with single BA interconnections, the tuning of the control system may require that the BA implement a Frequency Response Setting slightly greater in absolute terms than its actual Frequency Response to get the best performance.

- The new standardized measurement method for determining FRM in some cases results in a measured Frequency Response significantly lower than the previous methods used by some BAs. It is desirable to not require significant change in the Frequency Bias Setting for these BAs that experience a reduction in their measured Frequency Response.

Requirement 3

R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is:

- *Less than zero at all times, and*
- *Equal to or more negative than its Frequency Response Obligation when the Frequency varies from 60 Hz by more that +/- 0.036 Hz.*

Background and Rationale

In multi-Balancing Authority interconnections, the Frequency Bias Setting should be coordinated among all BAs on the interconnection. When there is a minimum Frequency Bias Setting requirement, it should apply for all BAs. However, BAs using a variable Frequency Bias Setting may have non-linearity in their actual response for a number of reasons including the dead-bands implemented on their generator governors. The measurement to ensure that these BAs are conforming to the interconnection minimum is adjusted to remove the dead-band range from the calculated average Frequency Bias Setting actually used. For BAs using variable bias, FRS Form 1 has a data entry location for the previous year's average monthly Bias. The Balancing Authority and the ERO can compare this value to the previous year's Frequency Bias Setting minimum to ensure R3 has been met.

On single BA interconnections, there is no need to coordinate the Frequency Bias Setting with other BAs. This eliminates the need to maintain a minimum Frequency Bias Setting for any reason other than meeting the reliability requirement as specified by the Frequency Response Obligation.

Requirement 4

R4. 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 to either:

- *The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or*

- *The Frequency Bias Setting as shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.*

Background and Rationale
This requirement reflects the operating principles first established by NERC Policy 1 and is similar to Requirement R6 of the approved BAL-003-0.1b standard. Overlap Regulation Service is a method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority's actual interchange, frequency response, and schedules into the providing Balancing Authority's AGC/ACE equation.

As noted earlier, a BA that is providing Overlap Regulation will report the sum of the Bias Settings in its FRS Form 1. Balancing Authorities receiving Overlap Regulation Service have an ACE and Frequency Bias Setting equal to zero (0).

How this Standard Meets the FERC Order No. 693 Directives

FERC Directive

The following is the relevant paragraph of Order No. 693.

> *Accordingly, the Commission approves Reliability Standard BAL-003-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to BAL-003-0 through the Reliability Standards development process that: (1) includes Levels of Non-Compliance; (2) determines the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other requirements of the Reliability Standard are being met, and to modify Measure M1 based on that determination and (3) defines the necessary amount of Frequency Response needed for Reliable Operation for each balancing authority with methods of obtaining and measuring that the frequency response is achieved.*

1. Levels of Non-Compliance

VRFs and VSLs are an equally effective way of assigning compliance elements to the standard.

2. Determine the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other Requirements of the Reliability Standard are met

BAL-003 V0 R2 (the basis of Order No. 693) deals with the calculation of Frequency Bias Setting such that it reflects natural Frequency Response.

The drafting team has determined that a sample size on the order of at least 20 events is necessary to have a high confidence in the estimate of a BA's Frequency Response. Selection of the frequency excursion events used for analysis will be done via a method outlined in Attachment A to the Standard.

On average, these events will represent the largest 2-3 "clean" frequency excursions occurring each month.

Since Frequency Bias Setting is an annual obligation, the survey of the at least 20 frequency excursion events will occur once each year.

3. Define the necessary amount of Frequency Response needed for Reliable Operation for each Balancing Authority with methods of obtaining and measuring that the frequency response is achieved

Necessary Amount of Frequency Response

The drafting team has proposed the following approach to defining the necessary amount of frequency response. In general, the goal is to avoid triggering the first step of under-frequency load shedding (UFLS) in the given Interconnection for reasonable contingencies expected. The methodology for determining each Interconnection's and Balancing Authority's obligation is outlined in Attachment A to the Standard.

It should be noted the standard cannot guarantee there will never be a triggering of UFLS as the magnitude of "point C" differs throughout an interconnection during a disturbance and there are local areas that see much wider swings in frequency.

The contingency protection criterion is the largest reasonably expected contingency in the Interconnection. This can be based on the largest observed credible contingency in the previous 10 years or the largest Category C event for the Interconnection.

Attachment A to the standard presents the base obligation by Interconnection and adds a Reliability Margin. The Reliability Margin included addresses the difference between Points B and C and accounts for variables.

For multiple BA interconnections, the Frequency Response Obligation is allocated to BAs based on size. This allocation will be based on the following calculation:

$$\mathrm{FRO_{BA}} = \mathrm{FRO_{Int}} \times \frac{\text{Annual Gen}_{\mathrm{BA}} + \text{Annual Load}_{\mathrm{BA}}}{\text{Annual Gen}_{\mathrm{Int}} + \text{Annual Load}_{\mathrm{Int}}}$$

Methods of Obtaining Frequency Response

The drafting team believes the following are valid methods of obtaining Frequency Response:

- Regulation services.
- Contractual service. The drafting team has developed an approach to obtain a contractual share of Frequency Response from Adjacent Balancing Authorities. See FRS Form 1. While the final rules with regard to contractual services are being defined, the current expectation is that the ERO and the associated Region(s) should be notified beforehand and that the service be at least 6 months in duration.
- Through a tariff (e.g. Frequency Response and regulation service).
- From generators through an interconnection agreement.
- Contract with an internal resource or loads (The drafting team encourages the development of a NAESB business practice for Frequency Response service for linear (droop) and stepped (e.g. LaaR in Texas) response).

Since NERC standards should not prescribe or preclude any particular market related service, BAs and FRSGs may use whatever is most appropriate for their situation.

Measuring that the Frequency Response is Achieved

FRS Form 1 and the underlying data retained by the BA will be used for measuring whether Frequency Response was provided. FRS Form 1 will provide the guidance on how to account for and measure Frequency Response.

Going Beyond the Directive

Based on the combined operating experience of the SDT, the drafting team consensus is that each Interconnection has sufficient Frequency Response. If margins decline, there may be a need for additional standards or tools. The drafting team and the Resources Subcommittee are working with the ERO on its Frequency Response Initiative to develop processes and good practices so the Interconnections are prepared. These good practices and tools are described in the following section.

The drafting team is also evaluating a risk-based approach for basing the Interconnection Frequency Response Obligation on an historic probability density of frequency error, and for allocating the obligation on the basis of the Balancing Authority's average annual ACE share of frequency error. This allocation method uses the inverse of the rationale for allocating the CPS1 epsilon requirement by Bias share.

Good Practices and Tools

Background

This section outlines tips and tools to help Balancing authorities meet the Frequency Response Standard or to operate more reliably. If you have suggested additions, please send them to balancing@nerc.com.

Identifying and Estimating Frequency Responsive Reserves

Knowing the quantity and depth of frequency responsive reserves in real time is a possible next step to being better prepared for the next event. The challenge in achieving this is having the knowledge of the capabilities of all sources of frequency response. Presently the primary source of Frequency Response remains with the generation resources in our fleets.

Understanding how each of these sources performs to changes in system frequency and knowing their limitations would improve the BA's ability to measure frequency responsive reserves. Presently there are only guidelines, criteria and protocols in some regions of the industry that identify specific settings and performance expectations of Primary Frequency Response of resources.

One method of gaining a better understanding of performance is to measure performance during actual events that occur on the system. Measuring performance during actual events would only provide feedback for performance during that specific event and would not provide insight into depth of response or other limitations.

Repeated measurements will increase confidence in expected performance. NERC modeling standards are in process to be revised that will improve the BA's insight into predicting available frequency responsive reserves. However, knowing how resources are operated, what modes of operation provide sustained Primary Frequency Response and knowing the operating range of this response would give the BA the knowledge to accurately predict frequency response and the amount of frequency responsive reserves available in real time.

Some benefits have been realized by communicating to generation resources (GO) the importance of operating in modes that allow Primary Frequency Response to be sustained by the control systems of the resource. Other improvements in implementation of Primary Frequency Response have been achieved through improved settings on turbine governors through the elimination of "step" frequency response with the simultaneous reduction in governor dead-band settings.

Improvements in the full AGC control loop of the generating resource, which accounts for the expected Primary Frequency Response, have improved the delivery of quality Primary Frequency Response while minimizing secondary control actions of generators. Some of these actions can provide quick improvement in delivery of Primary Frequency Response.

Once Primary Frequency Response sources are known, the BA could calculate available reserves that are frequency responsive. Planning for these reserves during normal and emergency operations could be developed and added to the normal planning process.

Using FRS Form 1 Data

The information collected for this standard can be supplemented by a few data points to provide the Balancing Authority useful tools and information. The BA could do a regression analysis of its frequency response against the following values:

- Load (value A).
- Interchange (Value A).
- Total generation.
- Spinning reserve.

While the last two values above are not part of Form 1, they should be readily available. Small BAs might even include headroom on its larger generators as part of the regression.

The regression would provide a formula the BA could program in its EMS to present the operator a real time estimate of the BA's Frequency Response.

Statistical outliers in the regression would point to cases meriting further inspection to find causes of low Frequency Response or opportunities for improvement.

Tools

Single generating resource performance evaluation tools for steam turbine, combustion turbine (simple cycle or combined cycle) and for intermittent resources are available at the following link. http://texasre.org/standards_rules/standardsdev/rsc/sar003/Pages/Default.aspx.

These tools and the regional standard associated with them are in their final stages of development in the Texas region.

These tools will be posted on the NERC website.

References

NERC *Frequency Response Characteristic Survey Training Document* (Found in the NERC Operating Manual)

NERC Resources Subcommittee Position Paper on Frequency Response

NERC TIS Report *Interconnection Criteria for Frequency Response Requirements (for the Determination Interconnection Frequency Response Obligations (IFRO)*

Frequency Response Standard Field Trial Analysis, September 17, 2012

Appendix 1 - Data Quality Concerns Related To The Use Of The Actual Net Interchange Value

Actual net interchange for a typical Balancing Authority (BA) is the summation of its tie lines to other BAs. In some cases, there are pseudo-ties in it which reflect the effective removal or addition of load and/or generation from another BA, or it could include supplemental regulation as well. But in the typical scenario, actual net interchange values that are extracted from EMS data archiving can be influenced by data latency times in the data acquisition process, and also any timestamp skewing in the archival process.

Of greater concern, however, are the inevitable variations of other operating phenomena occurring concurrently with a frequency event. The impacts of these phenomena are superimposed on actual net interchange values along with the frequency response that we wish to measure through the use of the actual net interchange value.

To explore this issue further, let's begin with the idealized condition:

- frequency is fairly stable at some value near or a little below 60 Hz
- ACE of the non-contingent BA of interest is 0 and has been 0 for an extended period, and AGC control signals have not been issued recently
- Actual net interchange is "on schedule", and there are no schedule changes in the immediate future
- BA load is flat
- All generators not providing AGC are at their targets
- Variable generation such as wind and solar are not varying
- Operators have not directed any manual movements of generation recently

And when the contingency occurs in this idealized state, the change in actual net interchange will be measuring only the decline in load due to lesser frequency and generator governor response, and, none of the contaminating influences. While the ACE may become negative due to the actual frequency response being less than that called for by the frequency bias setting within the BA's AGC system, this contaminating influence on measuring frequency response will not appear in the actual net interchange value if the measurement interval ends before the generation on AGC responds.

Now let's explore the sensitivity of the resultant frequency response sampling to the relaxation of these idealized circumstances.

1. The "60 Hz load" increases moderately due to time of day concurrent with the frequency event. If the frequency event happens before AGC or operator-directed manual load adjustments occur, then the actual net interchange will be reduced by the moderate increase in load and the frequency response will be underestimated. But if the frequency event happens while AGC response and/or manual adjustments occur, then the actual net interchange will be increased by the AGC response (and/or manual adjustments) and the frequency response will be overestimated.

2. The “60 Hz load” decreases moderately due to time of day concurrent with the frequency event. If the frequency event happens before AGC or operator-directed manual load adjustments occur, then the actual net interchange will be increased by the moderate reduction in load and the frequency response will be overestimated. But if the frequency event happens while AGC response and/or manual adjustments occur, then the actual net interchange will be decreased by the AGC response (and/or manual adjustments) and the frequency response will be underestimated.
3. In anticipation of increasing load during the next hour, the operator increases manual generation before the load actually appears. If the frequency event happens while the generation “leading” the load is increasing, then the actual net interchange will be increased by the increase in manual generation and the frequency response will be overestimated. But if the frequency event occurs when the result of AGC signals sent to offset the operator’s leading actions take effect, then the actual net interchange will be decreased and the frequency response is underestimated.
4. In anticipation of decreasing load during the next hour, the operator decreases manual generation before the load actually declines. If the frequency event happens while the generation “leading” the load downward is decreasing, then the actual net interchange will be decreased by the reduction in manual generation and the frequency response will be underestimated. But if the frequency event occurs when the result of AGC signals sent to offset the operator’s leading actions take effect, then the actual net interchange will be increased and the frequency response is overestimated.
5. A schedule change to export more energy is made at 5 minutes before the top of the hour. The BA’s “60 Hz load” is not changing. The schedule change is small enough that the operator is relying on upward movement of generators on AGC to provide the additional energy to be exported. The time at which the AGC generators actually begin to provide the additional energy is dependent on how much time passes before the AGC algorithm gets out of its deadbands, the individual generator control errors get large enough for sending out the control signal, and maybe 20 seconds to 3 minutes for the response to be effected. The key point here is that it is not clear when the effects of a schedule change, as manifested in a change in generation and then ultimately a change in actual net interchange, will occur.
6. With the expected penetration of wind in the near future, unanticipated changes in their output will tend to affect actual net interchange and add noise to the frequency response observation process.

To a greater or lesser extent, 1 through 4 above are happening continuously for the most part with most BAs in the Eastern and Western Interconnections. 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.

Proposed Resource Loss Protection Criteria

Background and Current Methodologies

The Resource Loss Protection Criteria (RLPC) is the respective Interconnection design resource loss in MW, which is used to determine the Interconnection Frequency Response Obligation (IFRO).
An "N-2 Event" is defined as a single initiating event that leads to multiple (two or more) electrical facilities being removed from service. Examples of this are breaker failure events, bus faults, or double circuit tower outages.

Previously, the RLPC has been calculated from the largest N-2 events identified in each Interconnection, except for the Eastern Interconnection. In the Eastern Interconnection, the RLPC has been calculated using the largest single event in the previous ten years.

The RLPC value should be set for each Interconnection such that the underfrequency load shedding safety net is not activated for the largest N-2 Event. The previous BAL-003 IFRO methodology determined that the largest N-2 Event should not precipitate an underfrequency load shedding event. Ideally, the RLPC value should always equal or exceed the largest N-2 Event. If the RLPC is set to a larger value than the largest N-2 Event, the probability of an underfrequency load shedding event decreases. If the RLPC value is set to a value less than the largest N-2 Event, the probability of an underfrequency load shedding event increases.

A quantitative approach for selecting the RLPC can be implemented that minimizes the need for detailed system analysis to be performed annually.

Currently, each Balancing Authority (BA) or Reserve Sharing Group (RSG) determines its Most Severe Single Contingency (MSSC) with respect to resource loss as required by BAL-002-2(i), Requirement R2. The MSSC calculation is done in Real-time operations based on actual system configuration.

Relevant Definitions

For convenience, the definitions of the following terms defined in the Glossary of Terms used in NERC Reliability Standards are provided below. Where a conflict exists between the definition provided here and the definition in the Glossary, the definition in the Glossary shall control.

Most Severe Single Contingency:
The Balancing Contingency Event, due to a single contingency identified using system models maintained within the RSG or a BA's area that is not part of a RSG, that would result in the greatest loss (measured in Megawatts (MWs) of resource output used by the RSG or a BA that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Balancing Contingency Event:
Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less.

A. Sudden loss of generation:
    a. Due to:
        i. unit tripping, or
        ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or
        iii. sudden unplanned outage of transmission Facility.
    b. And that causes an unexpected change to the responsible entity's Area Control Error (ACE).
B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.
C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Interconnection:
A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

Proposal
The Interconnection RLPC is calculated based on a resource loss in accordance with the following process:

NERC will request BAs to provide their two largest resource loss values and largest resource loss due to an N-1 or N-2 RAS event or largest resource as described above. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be needed to complete the calculation of the RLPC and IFRO.

BAs determine the two largest resource losses for the next operating year based on a review of the following items:

- The two largest Balancing Contingency Events due to a single contingency identified using system models in terms of loss measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)
- The two largest units in the BA Area, regardless of shared ownership/responsibility.

- The two largest Remedial Action Scheme (RAS) resource losses (if any) which are initiated by single (N-1) contingency events.

The BA provides these two numbers determined above as Resource Loss A and Resource Loss B in the FRS Form 1.

The BA should then provide the largest resource loss due to RAS operations (if any) which is initiated by a multiple contingency (N-2) event (RLPC cannot be lower than this value). If the RAS impacts more than a single BA, one BA is asked to take the lead and sum all resources lost due to the RAS event and provide that information.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.

The host BA (or planned host BA) where jointly-owned resources are physically located, should be the only BA to report that resource. The full ratings of the resource, not the fractional shares, should be reported.

Direct-current (DC) ties to asynchronous resources (such as DC ties between Interconnections, or the Manitoba Hydro Dorsey bi-pole ties to their northern asynchronous generation). DC lines, such as the Pacific DC Intertie, which ties two sections of the same synchronous interconnection together, should not be reported. A single pole block with normal clearing in a monopole or bi-pole high-voltage direct current system is a single contingency.

For a hypothetical four-BA Interconnection, Plant 1, in BA1, has two generators rated at 1200 MW each. Plant 2, in BA2 has a generator rated at 1400 MW. BA2's next largest contingency is 1000 MW. The two largest resource losses for BA3 and BA4 are listed below.

BA1	Resource Loss A = 1200 MW	Resource Loss B = 1200 MW	Both at Plant 1 (N-2)
BA2	Resource Loss A= 1400 MW	Resource Loss B = 1000 MW	Electrically separate
BA3	Resource Loss A = 1000 MW	Resource Loss B = 800 MW	Electrically separate
BA4	Resource Loss A = 1500 MW (DC TIE)	Resource Loss B= 500 MW	Electrically separate

The ERO would apply the RLPC selection methodology described above to determine the RLPC for the Interconnection. Using this methodology, results in the following:

Largest Resource Loss = 1500 MW
Second Largest Resource Loss = 1400 MW
Summation of two largest resource losses = 2900 MW
Interconnection RLPC = 2900 MW

If only the N-2 Event was applied, the RLPC for the Interconnection would be 2400 MW. The summation of the two largest Interconnection Resource Losses will equal or exceed, but never fall short of, the N-2 Event scenario.

In order to evaluate RAS resource loss, single (N-1) and multiple (N-2) contingency events should be evaluated.

Hypothetically, in an Interconnection:

BA1 RAS = 2850 MW N-2 RAS event
BA1 Resource Loss A = 1150 MW
BA1 Resource Loss B = 800 MW
BA2 Resource Loss A = 1380 MW
BA2 Resource Loss B = 1380 MW
BA3 RAS = 1000 MW N-1 RAS event
BA3 Resource Loss A = 800 MW
BA3 Resource Loss B = 700 MW

In this case, the ERO would determine the RLPC as follows: the summation of the two largest resource losses is 2760 MW. Since the N-2 RAS event exceeds the summation of the two largest single contingency events, the RLPC is the N-2 RAS event, or 2850 MW.

Interconnection RLPC Values

Based on initial review, the numbers below would be representative of the RLPC for each Interconnection.

Eastern Interconnection:
Present RLPC = 4500 MW Load Credit = 0 MW
RESOURCE LOSS A = 1732 MW
RESOURCE LOSS B = 1477 MW
Proposed RLPC = 3209 MW

Western Interconnection:
Present RLPC = 2626 MW Load Credit = 120 MW
RESOURCE LOSS A = 1505 MW
RESOURCE LOSS B = 1344 MW
N-2 RAS = 2850 MW
Proposed RLPC = 2850 MW

ERCOT:
Present RLPC = 2750 MW Load Credit = 1209 MW
RESOURCE LOSS A = 1375 MW
RESOURCE LOSS B = 1375 MW
Proposed RLPC = 2750 MW

Quebec Interconnection:
Present RLPC = 1700 MW Load Credit = 0 MW
RESOURCE LOSS A = 1000 MW

RESOURCE LOSS B = 1000 MW
Proposed RLPC = 2000 MW

Proposed Resource Loss Protection Criteria

Background and Current Methodologies

The Resource Loss Protection Criteria (RLPC) is the respective Interconnection design resource loss in MW, which is used to determine the Interconnection Frequency Response Obligation (IFRO).
An "N-2 Event" is defined as a single initiating event that leads to multiple (two or more) electrical facilities being removed from service. Examples of this are breaker failure events, bus faults, or double circuit tower outages.

Previously, the RLPC has been calculated from the largest N-2 events identified in each Interconnection, except for the Eastern Interconnection. In the Eastern Interconnection, the RLPC has been calculated using the largest single event in the previous ten years.

The RLPC value should be set for each Interconnection such that the underfrequency load shedding safety net is not activated for the largest N-2 Event. The ~~P~~previous BAL-003 IFRO methodology determined that the largest N-2 Event should not precipitate an underfrequency load shedding event. Ideally, the RLPC value should always equal or exceed the largest N-2 Event. If the RLPC is set to a larger value than the largest N-2 Event, the probability of an underfrequency load shedding event decreases. If the RLPC value is set to a value less than the largest N-2 Event, the probability of an underfrequency load shedding event increases.

A quantitative approach ~~to~~for selecting the RLPC can be implemented that minimizes the need for detailed system analysis to be performed annually.

Currently, each Balancing Authority (BA) or Reserve Sharing Group (RSG) determines its Most Severe Single Contingency (MSSC) with respect to resource loss as required by BAL-002-2(i), Requirement R2. The MSSC calculation is done in Real-time operations based on actual system configuration.

Relevant Definitions

For convenience, the definitions of the following terms defined in the Glossary of Terms used in NERC Reliability Standards are provided below. Where a conflict exists between the definition provided here and the definition in the Glossary, the definition in the Glossary shall control.

Most Severe Single Contingency:
The Balancing Contingency Event, due to a single contingency identified using system models maintained within the RSG or a BA's area that is not part of a RSG, that would result in the greatest loss (measured in Megawatts (MWs) of resource output used by the RSG or a BA that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

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   a. Due to:

      i. unit tripping, or

      ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or

      iii. sudden unplanned outage of transmission Facility.

   b. And that causes an unexpected change to the responsible entity's Area Control ~~Area~~ Error (ACE).

B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.

C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Interconnection:
A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

Proposal
The Interconnection RLPC is calculated based on a resource loss in accordance with the following process:

NERC will request ~~Balancing Authorities~~BAs to provide~~:~~ their two largest resource loss values and largest resource loss due to an N-1 or N-2 RAS event or largest resource as described above. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be needed to complete the calculation of the RLPC and IFRO.
~~NERC will request Balancing Authorities or Frequency Response Sharing Groups to provide: their two largest resource loss values and largest resource loss due to an N-1 or N-2 RAS event or largest resource as described above. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be voluntary on the part of the Balancing Authorities but will be needed to complete the calculation of the RLPC and IFRO.~~

~~Balancing Authorities~~BAs determine the two largest ~~potential~~ resource losses for the next operating year based on a review of the following items:

- The two largest Balancing Contingency Events due to a single contingency identified using system models in terms of loss measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)
- The two largest units in the BA Area, regardless of shared ownership/responsibility.
- The two largest Remedial Action Scheme (RAS) resource losses (if any) which are initiated by single (N-1) contingency events.

The BA provides these two numbers determined above as Resource Loss A and Resource Loss B in the FRS Form 1.

The BA should then provide the largest resource loss due to RAS operations (if any) which is initiated by a multiple contingency (N-2) event (RLPC cannot be lower than this value). If the~~is~~ RAS impacts more than a single BA, one BA is asked to take the lead and sum all resources lost due to the RAS event and provide that information.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.
The host BA (or planned host BA) where jointly-owned resources are physically located, should be the only BA to report that resource. The full ratings of the resource, not the fractional shares, should be reported.

Direct-current (DC) ties to asynchronous resources (such as DC ties between Interconnections, or the Manitoba Hydro Dorsey bi-pole ties to their northern asynchronous generation). DC lines such as the Pacific DC Intertie, which ties two sections of the same synchronous interconnection together, should not be reported. A single pole block with normal clearing in a monopole or bi-pole high-voltage direct current system is a single contingency.

For a hypothetical four-BA Interconnection, Plant 1, in BA1, has two generators rated at 1200 MW each. Plant 2, in BA2 has a generator rated at 1400 MW. BA2's next largest contingency is 1000 MW. The two largest resource losses for BA3 and BA4 are listed below.

BA1	Resource Loss A = 1200 MW	Resource Loss B = 1200 MW	Both at Plant 1 (N-2)
BA2	Resource Loss A= 1400 MW	Resource Loss B = 1000 MW	Electrically separate
BA3	Resource Loss A = 1000 MW	Resource Loss B = 800 MW	Electrically separate
BA4	Resource Loss A = 1500 MW (DC TIE)	Resource Loss B= 500 MW	Electrically separate

The ERO would apply the RLPC selection methodology described above to determine the RLPC for the Interconnection. Using this methodology, results in the following:

Largest Resource Loss = 1500 MW
Second Largest Resource Loss = 1400 MW
Summation of two largest resource losses = 2900 MW
Interconnection RLPC = 2900 MW

If only the N-2 Event was applied, the RLPC for the Interconnection would be 2400 MW. The summation of the two largest Interconnection Resource Losses will equal or exceed, but never fall short of, the N-2 Event scenario.

In order to evaluate RAS resource loss, single (N-1) and multiple (N-2) contingency events should be evaluated.

Hypothetically, in an Interconnection:

BA1 RAS = 2850 MW N-2 RAS event
BA1 Resource Loss A = 1150 MW
BA1 Resource Loss B = 800 MW
BA2 Resource Loss A = 1380 MW
BA2 Resource Loss B = 1380 MW
BA3 RAS = 1000 MW N-1 RAS event
BA3 Resource Loss A = 800 MW
BA3 Resource Loss B = 700 MW

In this ~~case~~case, the ERO would determine the RLPC as ~~follows,~~follows~~;~~: the summation of the two largest resource losses ~~are~~is 2760 MW. Since the N-2 RAS event exceeds the summation of the two largest single contingency events, the RLPC is the N-2 RAS event, or 2850 MW.

~~North American~~ Interconnection ~~RPLC~~ RLPC Values

Based on initial review, the numbers below ~~are believed to~~would be representative of the RLPC for each Interconnection.

Eastern Interconnection:
Present RLPC = 4500 MW Load Credit = 0 MW
~~MSSC1~~RESOURCE LOSS A = 1732 MW
~~MSSC2~~RESOURCE LOSS B = 1477 MW
Proposed RLPC = 3209 MW

Western Interconnection:
Present RLPC = 2626 MW Load Credit = 120 MW
~~MSSC1~~RESOURCE LOSS A = 1505 MW
~~MSSC2~~RESOURCE LOSS B = 1344 MW
N-2 RAS = 2850 MW
Proposed RLPC = 2850 MW

ERCOT:
Present RLPC = 2750 MW Load Credit = 1209 MW
~~MSSC1~~RESOURCE LOSS A = 1375 MW
~~MSSC2~~RESOURCE LOSS B = 1375 MW
Proposed RLPC = 2750 MW

Quebec Interconnection:
Present RLPC = 1700 MW Load Credit = 0 MW
~~MSSC1~~RESOURCE LOSS A = 1000 MW
~~MSSC2~~RESOURCE LOSS B = 1000 MW
Proposed RLPC = 2000 MW

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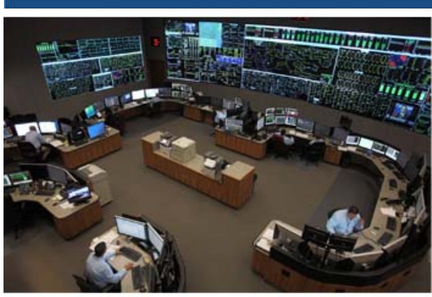
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

RELIABILITY | ACCOUNTABILITY



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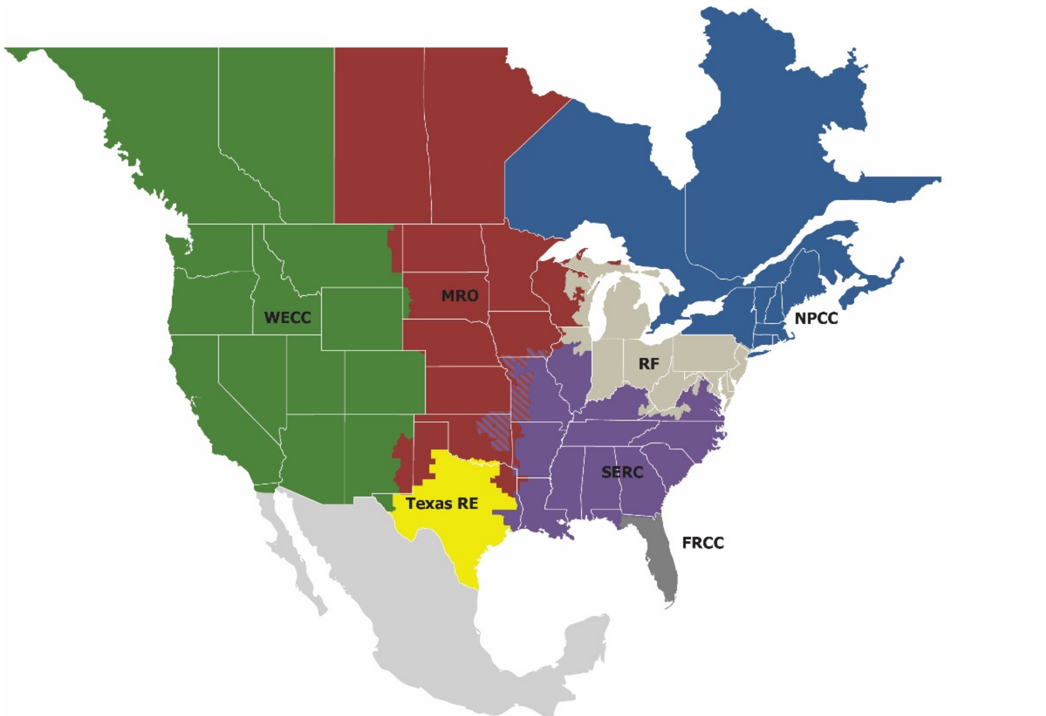
Preface

The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

The North American BPS is divided into seven RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



FRCC	Florida Reliability Coordinating Council
MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

This procedure (Procedure) outlines the Electric Reliability Organization (ERO) process for supporting the Frequency Response Standard (FRS). A request for revisions may be submitted to the Operating Committee (OC) of the ERO for consideration. The request must provide a technical justification for the suggested modification. The ERO shall publicly post the suggested modification for a 45-day formal comment period and discuss the request in a public meeting of the ERO OC. The ERO will make a recommendation to the NERC Board of Trustees (BOT), which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to this Procedure shall be filed with the Federal Energy Regulatory Commission (FERC) for informational purposes.

BAL-003-2 sets Interconnection Frequency Response Obligation (IFRO) to preset values subject to annual review. This procedure establishes the methods to be used for the annual review until Phase 2 of the SAR for Project 2017-01 has been addressed. If Frequency Response Measure (FRM) for the Eastern Interconnection degrades more than 10% in a year, the ERO will halt the reduction in IFRO until such time as a determination can be made as to the cause of the degradation.

Chapter 1: Event Selection Process

Event Selection Objectives

The goals of this procedure are to outline a transparent, repeatable process to annually identify a list of frequency events to be used to calculate Frequency Response to determine:

- Whether the Balancing Authority (BA) or Frequency Response Sharing Group (FRSG) met its Frequency Response Obligation, and
- An appropriate fixed Frequency Bias Setting.

Event Selection Criteria

1. The ERO will use the following criteria to select FRS excursion events for analysis. The events that best fit the criteria will be used to support the FRS. The evaluation period for performing the annual Frequency Bias Setting and the FRM calculation is December 1 of the prior year through November 30 of the current year.
2. The ERO will identify 20 to 35 frequency excursion events in each Interconnection for calculating the Frequency Bias Setting and the FRM. If the ERO cannot identify 20 frequency excursion events in a 12-month evaluation period satisfying the criteria below, then similar acceptable events from the subsequent year's evaluation period will be included with the data set by the ERO for determining compliance.
3. The ERO will use three criteria to determine if an acceptable frequency excursion event for the FRM has occurred:
    a. The change in frequency as defined by the difference from the A Value to Point C and the arrested frequency Point C exceeds the excursion threshold values specified for the Interconnection in Table 1 below.
        i. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline.
        ii. Point C is the arrested value of frequency observed within 20 seconds following the start of the excursion.

Table 1.1: Interconnection Frequency Excursion Threshold Values

Interconnection	A Value to Pt C	Point C (Low)	Point C (High)
East	0.04Hz	< 59.96	> 60.04
West	0.07Hz	< 59.95	> 60.05
ERCOT	0.15Hz	< 59.90	> 60.10
HQ	0.30Hz	< 59.85	> 60.15

    b. The time from the start of the rapid change in frequency until the point at which Frequency has stabilized within a narrow range should be less than 18 seconds.
    c. If any data point in the B Value average recovers to the A Value, the event will not be included.

4. Pre-disturbance frequency should be relatively steady and near 60.000 Hz for the A Value. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient

begins to decline. For example, given the choice of the two events below, the one on the right is preferred as the pre-disturbance frequency is stable and also closer to 60 Hz.

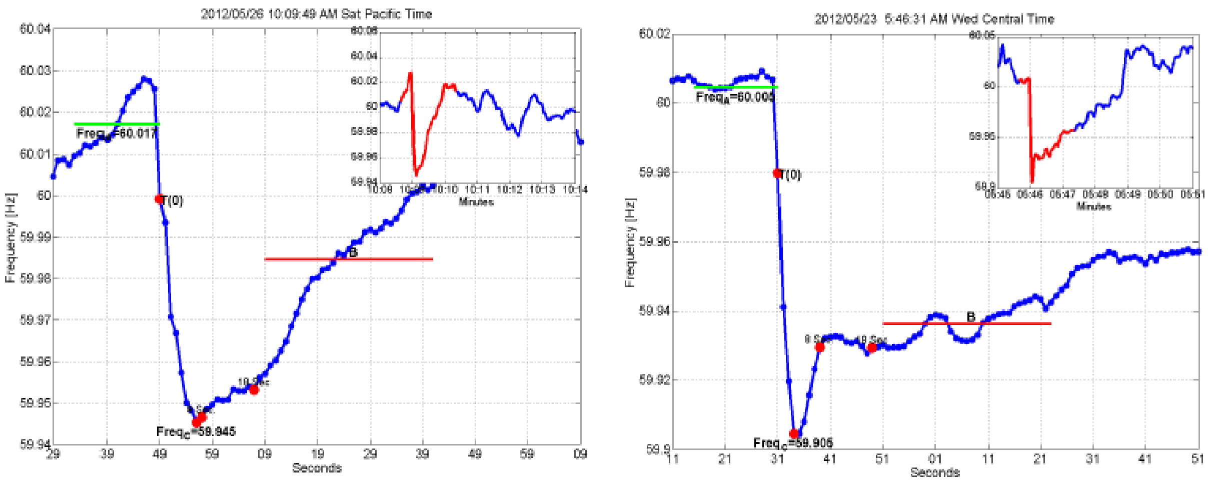


Figure 1.1: Pre-disturbance Frequency

5. Excursions that include 2 or more events that do not stabilize within 18 seconds will not be considered.
6. Frequency excursion events occurring during periods:
   a. when large interchange schedule ramping or load change is happening, or
   b. within 5 minutes of the top of the hour, will be excluded from consideration if other acceptable frequency excursion events from the same quarter are available.
7. The ERO will select the largest (A Value to Point C) 2 or 3 frequency excursion events occurring each month. If there are not 2 frequency excursion events satisfying the selection criteria in a month, then other frequency excursion events should be picked in the following sequence:
   a. From the same event quarter of the year.
   b. From an adjacent month.
   c. From a similar load season in the year (shoulder vs. summer/winter)
   d. The largest unused event.

As noted earlier, if a total of 20 events are not available in an evaluation year, then similar acceptable events from the next year's evaluation period will be included with the data set by the ERO for determining Frequency Response Obligation (FRO) compliance. The first year's small set of data will be reported and used for Bias Setting purposes, but compliance evaluation on the FRO will be done using a 24-month data set.

To assist Balancing Authority preparation for complying with this standard, the ERO will provide quarterly posting of candidate frequency excursion events for the current year FRM calculation. The ERO will post the final list of frequency excursion events used for standard compliance as specified in Attachment A of the standard. The following is a general description of the process that the ERO will use to ensure that BAs can evaluate events during the year in order to monitor their performance throughout the year.

Quarterly

The event lists will be reviewed quarterly, with the quarters defined as:

- December through February
- March through May
- June through August
- September through November

Based on criteria established in this Procedure, events will be selected to populate the FRS Form 1 for each Interconnection. The FRS Form 1's will be posted on the NERC website, in the Resources Subcommittee area under the title "Frequency Response Standard Resources". Updated FRS Form 1's will be posted at the end of each quarter listed above after a review by the NERC Resources Subcommittee (RS) and its Frequency Working Group. While the events on this list are expected to be final, as outlined in the selection criteria, additional events may be considered, if the number of events throughout the year do not create a list of at least 20 events. It is intended that this quarterly posting of updates to the FRS Form 1 would allow BAs to evaluate the events throughout the year, lessening the burden when the yearly posting is made.

Annually

The final FRS Form 1 for each Interconnection, which would contain the events from all four quarters listed above, will be posted as specified in Attachment A. Each Balancing Authority reports its previous year's Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO as specified in Attachment A using the final FRS Form 1. The ERO will check for errors and use the FRS Form 1 data to calculate CPS limits and FROs for the upcoming year.

Once the data listed above is fully reviewed, the ERO may adjust the implementation specified in Attachment A for changing the Frequency Bias Settings and CPS limits. This allows flexibility when each BA implements its settings.

Chapter 2: Process for Adjusting Interconnection Minimum Frequency Bias Setting

This procedure outlines the process the ERO is to use for modifying minimum Frequency Bias Settings to better meet reliability needs. The ERO will adjust the Frequency Bias Setting minimum in accordance with this procedure.
The ERO will post the minimum Frequency Bias Setting values on the ERO website along with other balancing standard limits.

Under BAL-003-2, the minimum Frequency Bias Settings will be moved toward the natural Frequency Response in each Interconnection. In the first year, the minimum Frequency Bias Setting for each Interconnection is shown in Table 2 below. Each Interconnection Minimum Frequency Bias Setting is based on the sum of the non-coincident peak loads for each BA from the currently available FERC 714 Report or equivalent. This non-coincident peak load sum is multiplied by the percentage shown in Table 2 to get the Interconnection Minimum Frequency Bias Setting. The Interconnection Minimum Frequency Bias Setting is allocated among the BAs on an Interconnection using the same allocation method as is used for the allocation of the Frequency Response Obligation (FRO).

Table 2.1: Frequency Bias Setting Minimums

Interconnection	Interconnection Minimum Frequency Bias Setting (in MW/0.1Hz)
Eastern	0.9% of non-coincident peak load
Western	0.9% of non-coincident peak load
ERCOT	N/A
HQ	N/A

*The minimum Frequency Bias Setting requirement does not apply to a Balancing Authority that is the only Balancing Authority in its Interconnection. These Balancing Authorities are solely responsible for providing reliable frequency control of their Interconnection. These Balancing Authorities are responsible for converting frequency error into a megawatt error to provide reliable frequency control, and the imposition of a minimum bias setting greater than the magnitude the Frequency Response Obligation may have the potential to cause control system hunting, and instability in the extreme.

The ERO, in coordination with the regions of each Interconnection, will annually review Frequency Bias Setting data submitted by BAs. 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 peak load (expressed in MW/0.1Hz), the minimum Frequency Bias Setting for BAs within that Interconnection may be reduced (in absolute value) in the subsequent years FRS Form 1 based on the technical evaluation and consultation with the regions affected by 0.1 percentage point of peak load (expressed in MW/0.1Hz) to better match that Frequency Bias Setting and natural Frequency Response.

The ERO, in coordination with the regions of each Interconnection, will monitor the impact of the reduction of minimum frequency bias settings, if any, on frequency performance, control performance, and system reliability. If unexpected and undesirable impacts such as, but not limited to, sluggish post-contingency restoration of frequency to schedule or control performance problems occur, then the prior reduction in the minimum frequency bias settings may be reversed, and/or the prospective reduction based on the criterion stated above may not be implemented.

Chapter 3: Interconnection Frequency Response Obligation Methodology

The Interconnection Resource Loss Protection Criteria (RLPC) is calculated based a resource loss in accordance with the following process:

NERC will request BAs to provide their two largest resource loss values and largest resource loss due to an N-1or N-2 RAS event or largest resource as described above. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be needed to complete the calculation of the RLPC and IFRO.

BAs determine the two largest resource losses for the next operating year based on a review of the following items:

- The two largest Balancing Contingency Events due to a single contingency identified using system models in terms of loss measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)
- The two largest units in the BA Area, regardless of shared ownership/responsibility.
- The two largest Remedial Action Scheme (RAS) resource losses (if any) which are initiated by single (N-1) contingency events.

The BA provides these two numbers determined above as Resource Loss A and Resource Loss B in the FR Form 1.

The BA should then provide the largest resource loss due to RAS operations (if any) which is initiated by a multiple contingency (N-2) event (RLPC cannot be lower than this value). If this RAS impacts more than a single BA, one BA is asked to take the lead and sum all resources lost due to the RAS event and provide that information.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.

The host BA (or planned host BA) where jointly-owned resources are physically located, should be the only BA to report that resource. The full ratings of the resource, not the fractional shares, should be reported.

Direct-current (DC) ties to asynchronous resources (such as DC ties between Interconnections, or the Manitoba Hydro Dorsey bi-pole ties to their northern asynchronous generation). DC lines such as the Pacific DC Intertie, which ties two sections of the same synchronous Interconnection together, should not be reported. A single pole block with normal clearing in a monopole or bi-pole high-voltage direct current system is a single contingency.

For a hypothetical four-BA Interconnection, Plant 1, in BA1, has two generators rated at 1200 MW each. Plant 2, in BA2 has a generator rated at 1400 MW. BA2's next largest contingency is 1000 MW. The two largest resource losses for BA3 and BA4 are listed below.

BA1	Resource Loss A = 1200 MW	Resource Loss B = 1200 MW	Both at Plant 1 (N-2)
BA2	Resource Loss A= 1400 MW	Resource Loss B = 1000 MW	Electrically separate
BA3	Resource Loss A = 1000 MW	Resource Loss B = 800 MW	Electrically separate
BA4	Resource Loss A = 1500 MW (DC TIE)	Resource Loss B = 500 MW	Electrically separate

The ERO would apply the RLPC selection methodology described above to determine the RLPC for the Interconnection. Using this methodology, results in the following:

Largest Resource Loss = 1500 MW
Second Largest Resource Loss = 1400 MW
Summation of two largest resource losses = 2900 MW
Interconnection RLPC = 2900 MW

If only the N-2 Event was applied, the RLPC for the Interconnection would be 2400 MW. The summation of the two largest Interconnection Resource Losses will equal or exceed, but never fall short of, the N-2 Event scenario.

In order to evaluate RAS resource loss, single (N-1) and multiple (N-2) contingency events should be evaluated.

Hypothetically, in an Interconnection:

BA1 RAS = 2850 MW	N-2 RAS event
BA1 Resource Loss A = 1150 MW	
BA1 Resource Loss B = 800 MW	
BA2 Resource Loss A = 1380 MW	
BA2 Resource Loss B = 1380 MW	
BA3 RAS = 1000 MW	N-1 RAS event
BA3 Resource Loss A = 800 MW	
BA3 Resource Loss B = 700 MW	

In this case, the ERO would determine the RLPC as follows: the summation of the two largest resource losses is 2760 MW. Since the N-2 RAS event exceeds the summation of the two largest single contingency events, the RLPC is the N-2 RAS event, or 2850 MW.

Interconnection RLPC Values

Based on initial review, the numbers below would be representative of the RLPC for each Interconnection.

Eastern Interconnection:
Present RLPC = 4500 MW   Load Credit = 0 MW
RESOURCE LOSS A = 1732 MW
RESOURCE LOSS B = 1477 MW
Proposed RLPC = 3209 MW

Western Interconnection:
Present RLPC = 2626 MW   Load Credit = 120 MW
RESOURCE LOSS A = 1505 MW
RESOURCE LOSS B = 1344 MW
N-2 RAS = 2850 MW
Proposed RLPC = 2850 MW

ERCOT:
Present RLPC = 2750 MW   Load Credit = 1209 MW
RESOURCE LOSS A = 1375 MW
RESOURCE LOSS B = 1375 MW
Proposed RLPC = 2750 MW

Quebec Interconnection:

Present RLPC = 1700 MW Load Credit = 0 MW

RESOURCE LOSS A = 1000 MW

RESOURCE LOSS B = 1000 MW

Proposed RLPC = 2000 MW

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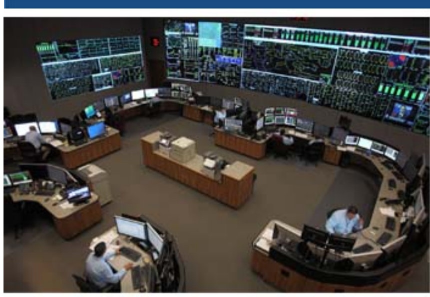
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

RELIABILITY | ACCOUNTABILITY



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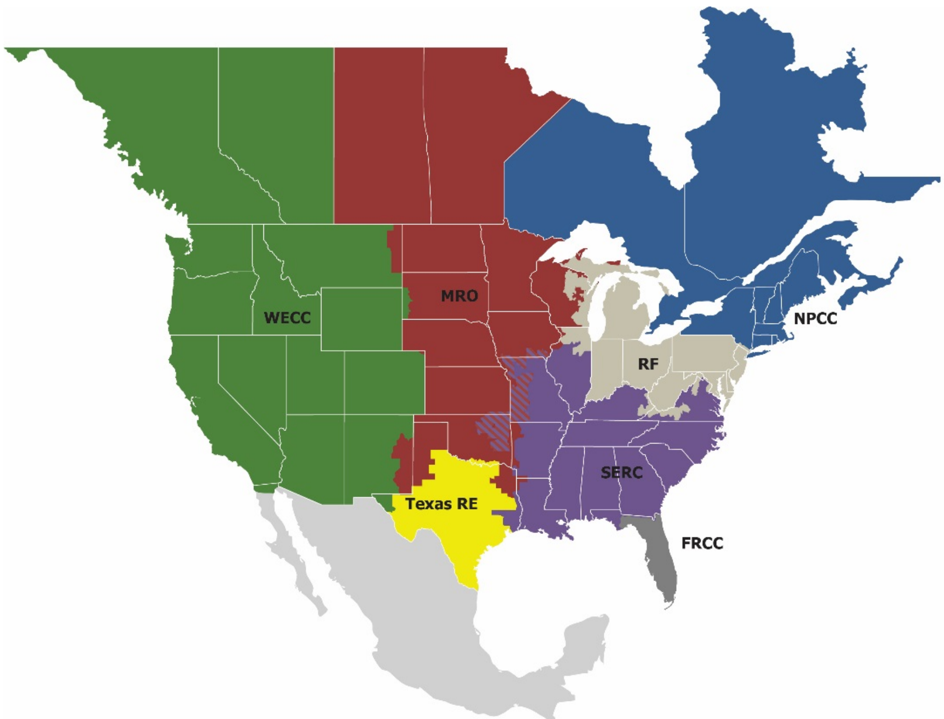

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RF	ReliabilityFirst
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Texas RE	Texas Reliability Entity
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Introduction

This procedure (Procedure) outlines the Electric Reliability Organization (ERO) process for supporting the Frequency Response Standard (FRS). A ~~Procedure revision~~ request for revisions may be submitted to the Operating Committee (OC) of the ERO for consideration. The ~~revision~~ request must provide a technical justification for the suggested modification. The ERO shall publicly post the suggested modification for a 45-day formal comment period and discuss the ~~revision~~ request in a public meeting of the ERO OC. The ERO will make a recommendation to the NERC ~~BOT~~Board of Trustees (BOT), which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to this Procedure shall be filed with the Federal Energy Regulatory Commission (FERC) for informational purposes.

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Chapter 1: Event Selection Process

Event Selection Objectives

The goals of this procedure are to outline a transparent, repeatable process to annually identify a list of frequency events to be used ~~by Balancing Authorities (BA)~~ to calculate ~~their~~ Frequency Response to determine:

- Whether the Balancing Authority (BA) or Frequency Response Sharing Group (FRSG) met its Frequency Response Obligation, and
- An appropriate fixed Frequency Bias Setting.

Event Selection Criteria

1. The ERO will use the following criteria to select FRS ~~frequency~~ excursion events for analysis. The events that best fit the criteria will be used to support the FRS. The evaluation period for performing the annual Frequency Bias Setting and the ~~Frequency Response Measure (~~FRM~~)~~ calculation is December 1 of the prior year through November 30 of the current year.
2. The ERO will identify 20 to 35 frequency excursion events in each Interconnection for calculating the Frequency Bias Setting and the FRM. If the ERO cannot identify 20 frequency excursion events in a 12-month evaluation period satisfying the criteria below, then similar acceptable events from the subsequent year's evaluation period will be included with the data set by the ERO for determining ~~FRS~~ compliance. ~~This is described later.~~
3. The ERO will use three criteria to determine if an acceptable frequency excursion event for the FRM has occurred:
    a. The change in frequency as defined by the difference from the A Value to Point C and the arrested frequency Point C exceeds the excursion threshold values specified for the Interconnection in Table 1 below.
        i. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline.
        ii. Point C is the arrested value of frequency observed within ~~12~~ 20 seconds following the start of the excursion.

Table 1.1: Interconnection Frequency Excursion Threshold Values

Interconnection	A Value to Pt C	Point C (Low)	Point C (High)
East	0.04Hz	< 59.96	> 60.04
West	0.07Hz	< 59.95	> 60.05
ERCOT	0.15Hz	< 59.90	> 60.10
HQ	0.30Hz	< 59.85	> 60.15

    b. The time from the start of the rapid change in frequency until the point at which Frequency has stabilized within a narrow range should be less than 18 seconds.
    c. If any data point in the B Value average recovers to the A Value, the event will not be included.

4. Pre-disturbance frequency should be relatively steady and near 60.000 Hz for the A Value. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline. For example, given the choice of the two events below, the one on the right is preferred as the pre-disturbance frequency is stable and also closer to 60 Hz.

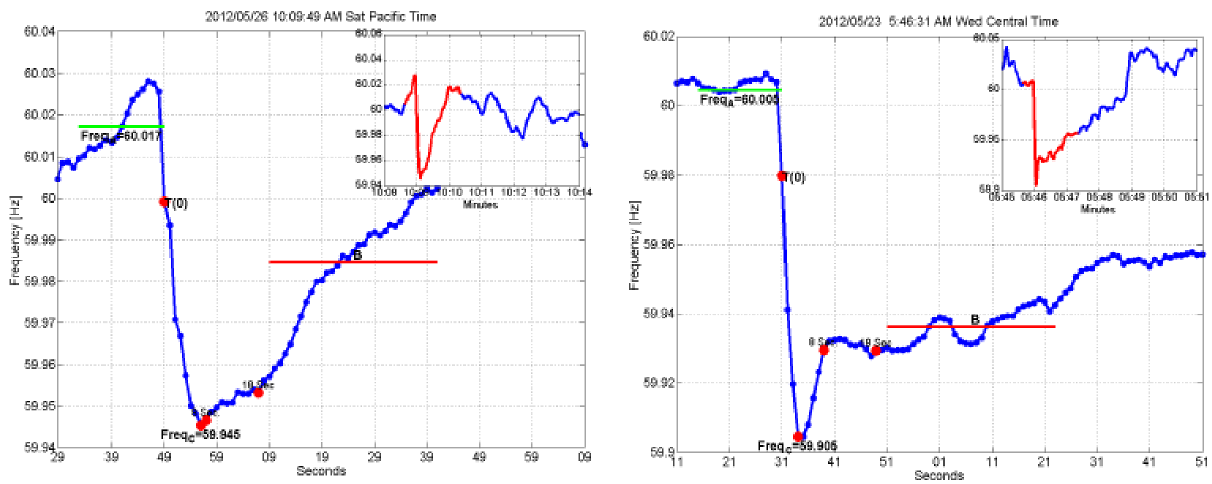


Figure 1.1: Pre-disturbance Frequency

5. Excursions that include 2 or more events that do not stabilize within 18 seconds will not be considered.
6. Frequency excursion events occurring during periods:
   a. when large interchange schedule ramping or load change is happening, or
   b. within 5 minutes of the top of the hour, will be excluded from consideration if other acceptable frequency excursion events from the same quarter are available.
7. The ERO will select the largest (A Value to Point C) 2 or 3 frequency excursion events occurring each month. If there are not 2 frequency excursion events satisfying the selection criteria in a month, then other frequency excursion events should be picked in the following sequence:
   a. From the same event quarter of the year.
   b. From an adjacent month.
   c. From a similar load season in the year (shoulder vs. summer/winter)
   d. The largest unused event.

As noted earlier, if a total of 20 events are not available in an evaluation year, then similar acceptable events from the next year's evaluation period will be included with the data set by the ERO for determining Frequency Response Obligation (FRO) compliance. The first year's small set of data will be reported and used for Bias Setting purposes, but compliance evaluation on the FRO will be done using a 24-month data set.

To assist Balancing Authority preparation for complying with this standard, the ERO will provide quarterly posting of candidate frequency excursion events for the current year FRM calculation. The ERO will post the final list of frequency excursion events used for standard compliance as specified in Attachment A of ~~BAL-003-1~~the standard.

The following is a general description of the process that the ERO will use to ensure that BAs can evaluate events during the year in order to monitor their performance throughout the year.

~~**Monthly**~~

~~Candidate events will be initially screened by the "Frequency Event Detection Methodology" shown on the following link located on the NERC Resources Subcommittee area of the NERC website: http://www.nerc.com/docs/oc/rs/Frequency_Event_Detection_Methodology_and_Criteria_Oct_2011.pdf. Each month's list will be posted by the end of the following month on the NERC website, http://www.nerc.com/filez/rs.html and listed under "Candidate Frequency Events".~~

Quarterly

The ~~monthly~~ event lists will be reviewed quarterly, with the quarters defined as:

- December through February
- March through May
- June through August
- September through November

Based on criteria established in ~~the~~ this Procedure~~"*Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*"~~, events will be selected to populate the FRS Form 1 for each Interconnection. The FRS Form 1's will be posted on the NERC website, in the Resources Subcommittee area under the title "Frequency Response Standard Resources". Updated FRS Form 1's will be posted at the end of each quarter listed above after a review by the NERC Resources Subcommittee (RS) and its Frequency Working Group. While the events on this list are expected to be final, as outlined in the selection criteria, additional events may be considered, if the number of events throughout the year do not create a list of at least 20 events. It is intended that this quarterly posting of updates to the FRS Form 1 would allow BAs to evaluate the events throughout the year, lessening the burden when the yearly posting is made.

Annually

The final FRS Form 1 for each Interconnection, which would contain the events from all four quarters listed above, will be posted as specified in Attachment A. Each Balancing Authority reports its previous year's Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO as specified in Attachment A using the final FRS Form 1. The ERO will check for errors and use the FRS Form 1 data to calculate CPS limits and FROs for the upcoming year.

Once the data listed above is fully reviewed, the ERO may adjust the implementation specified in Attachment A for changing the Frequency Bias Settings and CPS limits. This allows flexibility ~~in~~ when each BA implements its settings.

Chapter 2: Process for Adjusting Interconnection Minimum Frequency Bias Setting

This procedure outlines the process the ERO is to use for modifying minimum Frequency Bias Settings to better meet reliability needs. -The ERO will adjust the Frequency Bias Setting minimum in accordance with this procedure.
The ERO will post the minimum Frequency Bias Setting values on the ERO website along with other balancing standard limits.

Under BAL-003-~~1~~2, the minimum Frequency Bias Settings will be moved toward the natural Frequency Response in each ~~interconnection~~Interconnection. In the first year, the minimum Frequency Bias Setting for each ~~interconnection~~ Interconnection is shown in Table 2 below. -Each Interconnection Minimum Frequency Bias Setting is based on the sum of the non-coincident peak loads for each BA from the currently available FERC 714 Report or equivalent. -This non-coincident peak load sum is multiplied by the percentage shown in Table 2 to get the Interconnection Minimum Frequency Bias Setting. -The Interconnection Minimum Frequency Bias Setting is allocated among the BAs on an ~~interconnection~~ Interconnection using the same allocation method as is used for the allocation of the Frequency Response Obligation (FRO).

Table 2.1: Frequency Bias Setting Minimums	
Interconnection	**Interconnection Minimum Frequency Bias Setting (in MW/0.1Hz)**
Eastern	0.9% of non-coincident peak load
Western	0.9% of non-coincident peak load
ERCOT	N/A
HQ	N/A

*The minimum Frequency Bias Setting requirement does not apply to a Balancing Authority that is the only Balancing Authority in its Interconnection. -These Balancing Authorities are solely responsible for providing reliable frequency control of their Interconnection. –These Balancing Authorities are responsible for converting frequency error into a megawatt error to provide reliable frequency control, and the imposition of a minimum bias setting greater than the magnitude the Frequency Response Obligation may have the potential to cause control system hunting, and instability in the extreme.

The ERO, in coordination with the regions of each ~~interconnection~~Interconnection, will annually review Frequency Bias Setting data submitted by BAs. –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 peak load (expressed in MW/0.1Hz), the minimum Frequency Bias Setting for BAs within that Interconnection may be reduced (in absolute value) in the subsequent years FRS Form 1 based on the technical evaluation and consultation with the regions affected by 0.1 percentage point of peak load (expressed in MW/0.1Hz) to better match that Frequency Bias Setting and natural Frequency Response.

The ERO, in coordination with the regions of each Interconnection, will monitor the impact of the reduction of minimum frequency bias settings, if any, on frequency performance, control performance, and system reliability. If unexpected and undesirable impacts such as, but not limited to, sluggish post-contingency restoration of frequency to schedule or control performance problems occur, then the prior reduction in the minimum frequency bias settings may be reversed, and/or the prospective reduction based on the criterion stated above may not be implemented.

Chapter 3: Interconnection Frequency Response Obligation Methodology

The Interconnection Resource Loss Protection Criteria (RLPC) is calculated based a resource loss in accordance with the following process:

NERC will request BAs to provide their two largest resource loss values and largest resource loss due to an N-1or N-2 RAS event or largest resource as described above. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be needed to complete the calculation of the RLPC and IFRO.

BAs determine the two largest resource losses for the next operating year based on a review of the following items:

- The two largest Balancing Contingency Events due to a single contingency identified using system models in terms of loss measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)
- The two largest units in the BA Area, regardless of shared ownership/responsibility.
- The two largest Remedial Action Scheme (RAS) resource losses (if any) which are initiated by single (N-1) contingency events.

The BA provides these two numbers determined above as Resource Loss A and Resource Loss B in the FR Form 1.

The BA should then provide the largest resource loss due to RAS operations (if any) which is initiated by a multiple contingency (N-2) event (RLPC cannot be lower than this value). If this RAS impacts more than a single BA, one BA is asked to take the lead and sum all resources lost due to the RAS event and provide that information.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.

The host BA (or planned host BA) where jointly-owned resources are physically located, should be the only BA to report that resource. The full ratings of the resource, not the fractional shares, should be reported.

Direct-current (DC) ties to asynchronous resources (such as DC ties between Interconnections, or the Manitoba Hydro Dorsey bi-pole ties to their northern asynchronous generation). DC lines such as the Pacific DC Intertie, which ties two sections of the same synchronous Interconnection together, should not be reported. A single pole block with normal clearing in a monopole or bi-pole high-voltage direct current system is a single contingency.

For a hypothetical four-BA Interconnection, Plant 1, in BA1, has two generators rated at 1200 MW each. Plant 2, in BA2 has a generator rated at 1400 MW. BA2's next largest contingency is 1000 MW. The two largest resource losses for BA3 and BA4 are listed below.

BA1	Resource Loss A = 1200 MW	Resource Loss B = 1200 MW	Both at Plant 1 (N-2)
BA2	Resource Loss A= 1400 MW	Resource Loss B = 1000 MW	Electrically separate
BA3	Resource Loss A = 1000 MW	Resource Loss B = 800 MW	Electrically separate
BA4	Resource Loss A = 1500 MW (DC TIE)	Resource Loss B = 500 MW	Electrically separate

The ERO would apply the RLPC selection methodology described above to determine the RLPC for the Interconnection. Using this methodology, results in the following:

Largest Resource Loss = 1500 MW
Second Largest Resource Loss = 1400 MW
Summation of two largest resource losses = 2900 MW
Interconnection RLPC = 2900 MW

If only the N-2 Event was applied, the RLPC for the Interconnection would be 2400 MW. The summation of the two largest Interconnection Resource Losses will equal or exceed, but never fall short of, the N-2 Event scenario.

In order to evaluate RAS resource loss, single (N-1) and multiple (N-2) contingency events should be evaluated.

Hypothetically, in an Interconnection:

BA1 RAS = 2850 MW N-2 RAS event
BA1 Resource Loss A = 1150 MW
BA1 Resource Loss B = 800 MW
BA2 Resource Loss A = 1380 MW
BA2 Resource Loss B = 1380 MW
BA3 RAS = 1000 MW N-1 RAS event
BA3 Resource Loss A = 800 MW
BA3 Resource Loss B = 700 MW

~~This procedure outlines the process the ERO is to use for determining the Interconnection Frequency Response Obligation (IFRO).~~

~~The following are the formulae that comprise the calculation of the IFROs.~~

$$DF_{Base} = F_{start} - UFLS$$

$$DF_{CC} = DF_{Base} - CC_{Adj}$$

$$DF_{CBR} = \frac{DF_{CC}}{CB_R}$$

$$MDF = DF_{CBR} - BC'_{Adj}$$

$$ARCC = RCC - CLR$$

$$IFRO = \frac{ARCC}{10 * MDF}$$

~~Where:~~

- ~~DF~~$_{Base}$ ~~is the base delta frequency.~~
- ~~FStart is the starting frequency determined by the statistical analysis.~~
- ~~UFLS is the highest UFLS trip setpoint for the interconnection.~~

- ~~CCAdj is the adjustment for the differences between 1 second and sub second Point C observations for frequency events. A positive value indicates that the sub second C data is lower than the 1 second data.~~
- ~~DFCC is the delta frequency adjusted for the differences between 1 second and sub second Point C observations for frequency events.~~
- ~~CBR is the statistically determined ratio of the Point C to Value B.~~
- ~~DFCBR is the delta frequency adjusted for the ratio of the Point C to Value B.~~
- ~~BC'ADJ is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.~~
- ~~MDF is the maximum allowable delta frequency.~~
- ~~RCC is the resource contingency criteria.~~
- ~~CLR is the credit for load resources.~~
- ~~ARCC is the adjusted resource contingency criteria adjusted for the credit for load resources.~~
- ~~IFRO is the interconnection frequency response obligation.~~

  In this case, the ERO would determine the RLPC as follows: the summation of the two largest resource losses is 2760 MW. Since the N-2 RAS event exceeds the summation of the two largest single contingency events, the RLPC is the N-2 RAS event, or 2850 MW.

Interconnection RLPC Values

Based on initial review, the numbers below would be representative of the RLPC for each Interconnection.

Eastern Interconnection:
Present RLPC = 4500 MW Load Credit = 0 MW
RESOURCE LOSS A = 1732 MW
RESOURCE LOSS B = 1477 MW
Proposed RLPC = 3209 MW

Western Interconnection:
Present RLPC = 2626 MW Load Credit = 120 MW
RESOURCE LOSS A = 1505 MW
RESOURCE LOSS B = 1344 MW
N-2 RAS = 2850 MW
Proposed RLPC = 2850 MW

ERCOT:
Present RLPC = 2750 MW Load Credit = 1209 MW
RESOURCE LOSS A = 1375 MW
RESOURCE LOSS B = 1375 MW
Proposed RLPC = 2750 MW

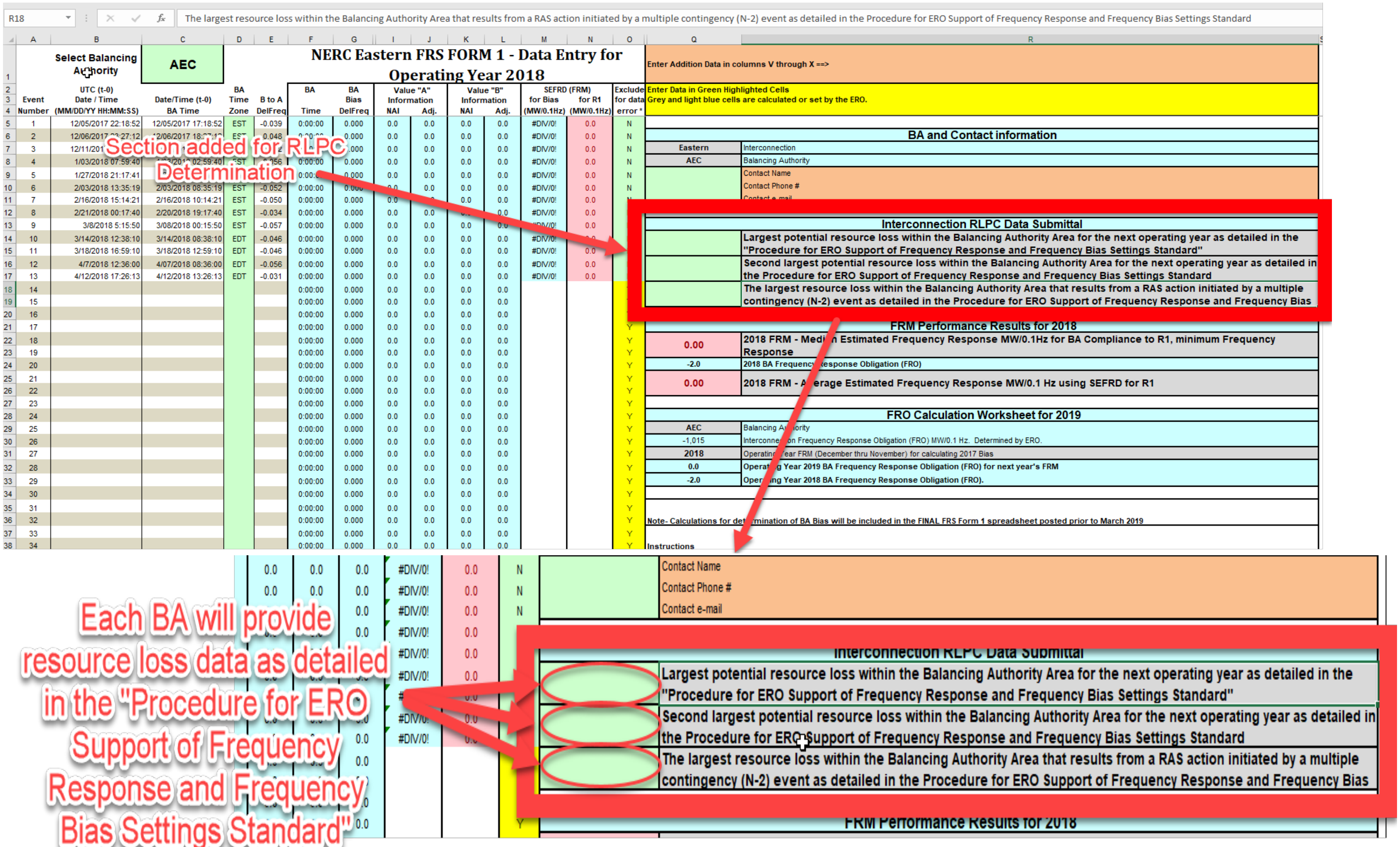
Quebec Interconnection:
Present RLPC = 1700 MW Load Credit = 0 MW
RESOURCE LOSS A = 1000 MW
RESOURCE LOSS B = 1000 MW
Proposed RLPC = 2000 MW

FRS Form 1 is a complex spreadsheet. To view the version posted with Draft 1 of the standard, please go to this address:

https://www.nerc.com/pa/Stand/Project201701ModificationstoBAL00311/Eastern%20Int%20FRS_Form_1-2018_Modified%20for%20SDT.xlsm

Modification to FRS Form 1

Each Balancing Authority (BA) including those within a Frequency Response Sharing Group (FRSG) provides data for the determination of the appropriate Interconnection's Resource Loss Protection Criteria (RLPC). In addition to the current practice of providing their frequency response sampling for all four quarters and their Frequency Bias Setting (FBS) calculation, each BA provides requested information regarding determination of resource losses and potential maximum resource loss due to Remedial Action Scheme (RAS) actions as detailed in the "Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard". For BAs that do not have facilities that meet the defined criteria, the entity would enter "0" in the appropriate cell. It would be expected that "load only" BAs would not have resources to report, as well as "generation only" BAs that have only a single resource. It is also expected that most BAs would not have RAS actions that include loss of resources larger than their reported resource losses. To facilitate the collection of data, the FRS Form 1 has been modified with the addition of the following fields.



R18
The largest resource loss within the Balancing Authority Area that results from a RAS action initiated by a multiple contingency (N-2) event as detailed in the Procedure for ERO Support of Frequency Response and Frequency Bias Settings Standard
Select Balancing Authority
AEC
NERC Eastern FRS FORM 1 - Data Entry for Operating Year 2018
Enter Addition Data in columns V through X ==>
Enter Data in Green Highlighted Cells
Grey and light blue cells are calculated or set by the ERO.
BA and Contact information
Eastern
Interconnection
AEC
Balancing Authority
Contact Name
Contact Phone #
Section added for RLPC Determination
Interconnection RLPC Data Submittal
Largest potential resource loss within the Balancing Authority Area for the next operating year as detailed in the "Procedure for ERO Support of Frequency Response and Frequency Bias Settings Standard"
Second largest potential resource loss within the Balancing Authority Area for the next operating year as detailed in the Procedure for ERO Support of Frequency Response and Frequency Bias Settings Standard
The largest resource loss within the Balancing Authority Area that results from a RAS action initiated by a multiple contingency (N-2) event as detailed in the Procedure for ERO Support of Frequency Response and Frequency Bias
FRM Performance Results for 2018
FRO Calculation Worksheet for 2019
Note- Calculations for determination of BA Bias will be included in the FINAL FRS Form 1 spreadsheet posted prior to March 2019
Instructions
Contact Name
Contact Phone #
Contact e-mail
Each BA will provide resource loss data as detailed in the "Procedure for ERO Support of Frequency Response and Frequency Bias Settings Standard"

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2017-01 Modifications to BAL-003-1.1

Formal Comment Period Open through January 17, 2019
Ballot Pools Forming through January 2, 2019

Now Available

A 45-day formal comment period for **Project 2017-01 Modifications to BAL-003-1.1**, is open through **8 p.m. Eastern, Thursday, January 17, 2019.**

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience issues navigating the SBS, contact Linda Jenkins. An unofficial Word version of the comment form is posted on the project page.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Initial ballots for the Standard and Implementation Plan, along with non-binding polls for the associated Violation Risk Factors and Violation Severity Levels, will be conducted **January 8 – January 17, 2019.**

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

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

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/160)
Ballot Name: 2017-01 Modifications to BAL-003-1.1 BAL-003-2 IN 1 ST
Voting Start Date: 1/8/2019 12:01:00 AM
Voting End Date: 1/17/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 196
Total Ballot Pool: 213
Quorum: 92.02
Quorum Established Date: 1/17/2019 10:28:02 AM
Weighted Segment Value: 96.41

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	60	1	41	0.953	2	0.047	0	10	7
Segment: 2	7	0.7	7	0.7	0	0	0	0	0
Segment: 3	45	1	36	0.947	2	0.053	0	6	1
Segment: 4	10	0.6	6	0.6	0	0	0	0	4
Segment: 5	48	1	35	0.946	2	0.054	0	7	4
Segment: 6	36	1	30	0.938	2	0.063	0	3	1
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	4	0.4	4	0.4	0	0	0	0	0
Totals:	213	6	162	5.784	8	0.216	0	26	17

BALLOT POOL MEMBERS

Show All ▾ entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Matthew Lewis		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Abstain	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras	Tamara Evey	Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Edison International - Southern California Edison Company	Romel Aquino		Abstain	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Georgia System Operations Corporation	Scott McGough		Abstain	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
3	Puget Sound Energy, Inc.	Tim Womack		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Robert Kondziolka		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		None	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Abstain	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Abstain	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		None	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Abstain	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/160)
Ballot Name: 2017-01 Modifications to BAL-003-1.1 Implementation Plan IN 1 OT
Voting Start Date: 1/8/2019 12:01:00 AM
Voting End Date: 1/17/2019 8:00:00 PM
Ballot Type: OT
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 192
Total Ballot Pool: 211
Quorum: 91
Quorum Established Date: 1/17/2019 10:31:26 AM
Weighted Segment Value: 99.04

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	59	1	41	1	0	0	0	10	8
Segment: 2	7	0.7	7	0.7	0	0	0	0	0
Segment: 3	45	1	35	0.972	1	0.028	0	7	2
Segment: 4	10	0.5	5	0.5	0	0	0	1	4
Segment: 5	47	1	34	0.971	1	0.029	0	8	4
Segment: 6	36	1	32	1	0	0	0	3	1
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	4	0.4	4	0.4	0	0	0	0	0
Totals:	211	5.9	161	5.844	2	0.056	0	29	19

BALLOT POOL MEMBERS

Show All ▾ entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Daniel Gacek		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Matthew Lewis		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Abstain	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras	Tamara Evey	Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Abstain	N/A
3	Exelon	Kinte Whitehead		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Georgia System Operations Corporation	Scott McGough		Abstain	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PPL - Louisville Gas and Electric Co.	Joseph Bencomo		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
3	Puget Sound Energy, Inc.	Tim Womack		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Robert Kondziolka		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Exelon	Cynthia Lee		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		None	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Abstain	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Omaha Public Power District	Mahmood Safi		None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Abstain	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		None	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Abstain	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/160)
Ballot Name: 2017-01 Modifications to BAL-003-1.1 BAL-003-2 Non-Binding Poll IN 1 NB
Voting Start Date: 1/8/2019 12:01:00 AM
Voting End Date: 1/17/2019 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 185
Total Ballot Pool: 204
Quorum: 90.69
Quorum Established Date: 1/17/2019 10:29:41 AM
Weighted Segment Value: 93.89

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	57	1	30	0.938	2	0.063	19	6
Segment: 2	7	0.4	4	0.4	0	0	3	0
Segment: 3	45	1	29	0.935	2	0.065	12	2
Segment: 4	8	0.4	4	0.4	0	0	0	4
Segment: 5	46	1	28	0.933	2	0.067	11	5
Segment: 6	34	1	22	0.917	2	0.083	8	2
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	4	0.3	3	0.3	0	0	1	0
Totals:	204	5.4	123	5.123	8	0.277	54	19

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Abstain	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	John Shaver		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Ryan Ziegler		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Bonneville Power Administration	Kammy Rogers-Holliday		Negative	Comments Submitted
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Larry Nash		Abstain	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Daniel Gacek		Abstain	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Lower Colorado River Authority	Matthew Lewis		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Mike Smith		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Abstain	N/A
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Abstain	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Seminole Electric Cooperative, Inc.	Mark Churilla		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Katherine Prewitt		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Abstain	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Abstain	N/A
2	California ISO	Richard Vine		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	AEP	Leanna Lamatrice		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras	Tamara Evey	Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Negative	Comments Submitted
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Annette Johnston		Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Abstain	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Abstain	N/A
3	Exelon	Kinte Whitehead		Abstain	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Georgia System Operations Corporation	Scott McGough		Abstain	N/A
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Affirmative	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
3	Puget Sound Energy, Inc.	Tim Womack		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Robert Kondziolka		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Seattle City Light	Tuan Tran		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jeff Neas		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Shirley Mathew		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Negative	Comments Submitted
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Abstain	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Exelon	Cynthia Lee		Abstain	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		None	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Abstain	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	PSEG - PSEG Fossil LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Abstain	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		None	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Exelon	Becky Webb		Abstain	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Ryan Streck		Affirmative	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	N/A
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Jennifer Sykes		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Abstain	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

Previous 1 Next

Showing 1 to 204 of 204 entries

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2017-01 Modifications to BAL-003-1.1

Formal Comment Period Open through January 17, 2019
Ballot Pools Forming through January 2, 2019

Now Available

A 45-day formal comment period for **Project 2017-01 Modifications to BAL-003-1.1**, is open through **8 p.m. Eastern, Thursday, January 17, 2019.**

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience issues navigating the SBS, contact Linda Jenkins. An unofficial Word version of the comment form is posted on the project page.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Initial ballots for the Standard and Implementation Plan, along with non-binding polls for the associated Violation Risk Factors and Violation Severity Levels, will be conducted **January 8 – January 17, 2019.**

For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

Comment Report

Project Name:	2017-01 Modifications to BAL-003-1.1
Comment Period Start Date:	12/4/2018
Comment Period End Date:	1/17/2019
Associated Ballots:	2017-01 Modifications to BAL-003-1.1 BAL-003-2 IN 1 ST 2017-01 Modifications to BAL-003-1.1 BAL-003-2 Non-Binding Poll IN 1 NB 2017-01 Modifications to BAL-003-1.1 Implementation Plan IN 1 OT

There were 23 sets of responses, including comments from approximately 93 different people from approximately 69 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The SDT proposes to replace Resource Contingency Criteria (RCC) with the Resource Loss Protection Criteria (RLPC). This criterion will be applied consistently across all Interconnections, and is designed to produce adequate reliability for each Interconnection. The RLPC determination methodology is detailed for this posting in the *Resource Loss Protection Criteria* Section of the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document and further in the *Resource Loss Protection Criteria* document. Is this methodology appropriate for determining the magnitude of the resource loss events that each Interconnection should protect against to assure an adequate level of reliability? If not, please provide an alternative proposal and any comments to the *Resource Loss Protection Criteria* document, which has been revised based on industry comment.

2. The SDT proposes fixing IFROs for a period that will continue until Phase 2 of the Project 2017-01 is completed. Do you agree with keeping IFROs as scheduled in Attachment A during the remainder of Project 2017-01? If you do not agree, please provide an alternative. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

3. The SDT is proposing to move items not related to entity compliance from BAL-003-1.1, Attachment A to the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document. Changes to this document will be subject to approval by the NERC Board of Trustees and informational filing to FERC. Do you agree that the SDT's proposed changes are appropriate? If not, please provide an alternative. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

4. Please provide any additional comments for the SDT to consider that have not already been provided in the questions above.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Powert	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
PPL - Louisville Gas and Electric Co.	Devin Shines	3,5,6	RF,SERC	Louisville Gas and Electric Company and Kentucky Utilities	Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					JULIE	PPL -	5	SERC

				Company	HOSTRANDER	Louisville Gas and Electric Co.		
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
Southwest Power Pool, Inc. (RTO)	Jim Williams	2	MRO,SERC	SPP Standards Review Group	Jim Williams	SPP	2	MRO
					Shannon Mickens	SPP	2	MRO
ACES Power Marketing	Jodirah Green	6	NA - Not Applicable	ACES Standard Collaborations	John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3,6	Texas RE
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Jenny Knernschield	Old Dominion Electric Cooperative	3,4	SERC
DTE Energy - Detroit Edison Company	Karie Barczak	3		DTE Energy - DTE Electric	Jeffrey Depriest	DTE Energy - DTE Electric	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
PJM Interconnection, L.L.C.	Mark Holman	2		SRC	Brandon Gleason	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	SERC
					Ali Miremadi	California ISO	2	WECC
					Helen Laines	Independent Electric	2	NPCC

						System Operator		
					Kathleen Goodman	ISO New England	2	NPCC
					Mark Holman	PJM Interconnection	2	RF
					Terry Bilke	Midcontinent Independent System Operator	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC
Manitoba Hydro	Mike Smith	1		Manitoba Hydro	Yuguang Xiao	Manitoba Hydro	5	MRO
					Karim Abdel-Hadi	Manitoba Hydro	3	MRO
					Blair Mukanik	Manitoba Hydro	6	MRO
					Mike Smith	Manitoba Hydro	1	MRO
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Jones	National Grid	3	NPCC
					Sean Cavote	PSEG	4	NPCC
					Kathleen	ISO-NE	2	NPCC

Goodman			
David Kiguel	Independent	NA - Not Applicable	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
Gregory Campoli	New York Independent System Operator	2	NPCC
Caroline Dupuis	Hydro Quebec	1	NPCC
Chantal Mazza	Hydro Quebec	2	NPCC
Michael Forte	Con Edison	1	NPCC
Laura McLeod	NB Power Corporation	5	NPCC
Nick	Kowalczyk	1	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
John Hastings	National Grid	1	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Sofia Gadea-Omelchenko	Con Edison	5	NPCC
Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
Quintin Lee	Eversource Energy	1	NPCC
Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC

					Shivaz Chopra	New York Power Authority	5	NPCC

1. The SDT proposes to replace Resource Contingency Criteria (RCC) with the Resource Loss Protection Criteria (RLPC). This criterion will be applied consistently across all Interconnections, and is designed to produce adequate reliability for each Interconnection. The RLPC determination methodology is detailed for this posting in the *Resource Loss Protection Criteria* Section of the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document and further in the *Resource Loss Protection Criteria* document. Is this methodology appropriate for determining the magnitude of the resource loss events that each Interconnection should protect against to assure an adequate level of reliability? If not, please provide an alternative proposal and any comments to the *Resource Loss Protection Criteria* document, which has been revised based on industry comment.

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	

Comment

AZPS appreciates the changes that were made that largely address our concerns and many others in the industry. AZPS now largely supports the RLPC with one important distinction. We believe the description of the RLPC is inaccurately described in the first bullet of Chapter 3 of the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.

“The two largest Balancing Contingency Events due to a single contingency identified using system models in terms of loss measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.) ”

We do not believe the intent is two events that are caused by a single contingency, which would be an N-2. Perhaps a better way to state what is intended is the language used in the proposed BAL-003-2, “the two largest potential Balancing Contingency Events that exist within a Balancing Authority identified using system models in terms of loss measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)”

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	Yes
Document Name	

Comment

The proposed methodology does appear to produce consistent results; however it represents a resource loss that may not actually manifest itself in practice. It does appear to provide a reasonable margin to reduce the potential for triggering UFLS operation due to insufficient frequency response. We appreciate the efforts of the SDT, however we believe it needs to be recognized that the proposed methodology is based-on (as well as highly dependent-on) the current resource mix and configuration.

Likes 0	
Dislikes 0	

Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC) and has one additional comment under item 4 below.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA supports replacing the Resource Contingency Criteria (RCC) with the Resource Loss Protection Criteria (RLPC). BPA agrees this methodology is appropriate for determining the magnitude of the resource loss events that each Interconnection should protect against to assure an adequate level of reliability. BPA suggests that the SDT review the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* to ensure that the language regarding RLPC matches the *Resource Loss Protection Criteria* document.	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	
Comment	
Louisville Gas and Electric Company and Kentucky Uitilities Company (LG&E/KU) generally agree with the proposed methodology. However, Page 1 of the RLPC document contains the statement: “The MSSC calculation is done in Real-time operations based on actual system configuration.” However,	

not every BA or RSG determines MSSC in real time – many do not. We recommend the SDT delete this statement for accuracy.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
We believe replacing the RCC with the RLPC will bring consistency across all interconnections and will eliminate the need of having a higher expectation from the Eastern Interconnection. Additionally, revising the verbiage associated with the MSSC, as one the basis for IFRO, has improved the overall technicality of the RPLC.	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2, Group Name SRC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ozan Ferrin - Tacoma Public Utilities (Tacoma, WA) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. The SDT proposes fixing IFROs for a period that will continue until Phase 2 of the Project 2017-01 is completed. Do you agree with keeping IFROs as scheduled in Attachment A during the remainder of Project 2017-01? If you do not agree, please provide an alternative. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
AZPS questions the logic that the newly proposed methodology for IFRO would only be valid to apply this one time until after Phase Two is completed. If it is believed that this IFRO methodology is technically valid, then it should be valid until an approved alternative is determined and approved. AZPS would also suggest leaving the currently determined values based on this methodology out of the actual standard since all of the contributing elements are subject to change based on the procedure and could quickly become inaccurate. It may be more appropriate to publish the currently determined values in the procedure, which can be updated often as necessary, and not in the standard.	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

There are several reasons that BPA cannot agree with keeping IFROs as scheduled in the revised Attachment A during the remainder of Project 2017-01.

-
    - The IFRO First Step for the Western Interconnection includes a Load Credit of 120 MW. There is no Load Credit for a PDCI RAS event.

Alternative approach: BPA asks that the First Step for WECC be recalculated without the Load Credit applied.

-
    - It is apparent that the First Step IFRO in the BAL-003 redline was calculated as (RLPC - Load Credit) / 10 * MDF

However, it is not apparent how the Max Delta Frequency (MDF) was determined since the tables with subcomponents such as the CBR (C to B ratio) are missing from the standard or a supporting document. The standard does say: "Detailed descriptions of the calculations used in Table 1 below are defined in the Procedure for *ERO Support of Frequency Response and Frequency Bias Setting Standard*." But the *ERO Support of Frequency Response and Frequency Bias Setting Standard* does not detail at all how the calculations used in Table 1 are defined, because the calculations were removed from that document.

Alternative approach: BPA recommends that the methodology for determining IFRO and MDF be detailed in Attachment A and that Table 1 be moved to a NERC document that can be updated yearly. The IFRO and MDF are key components of the current standard and the methodology for calculating it must be in Attachment A so that it cannot change without industry vote and FERC approval. BPA supports a change in the IFRO methodology through Phase II of Project 2017-01, at which point Attachment A should be updated.

-
    - The revised standard states that "**To reduce risk, the Eastern Interconnection IFRO will be stepped down annually from the 2017 value of -1,015 MW/0.1 Hz in -100 MW/0.1 Hz increments. If during the step down process, Interconnection Frequency Response Measure (FRM) declines by more than 10% percent, the ERO will halt the reduction in IFRO until such times that a determination can be made as to the cause of the degradation."

    BPA believes that this is not adequate for reliability.

    Alternative approach: BPA recommends that if the Interconnection Frequency Response Measure (FRM) declines by more than 10% percent, the ERO raise the IFRO back to the previous step.

Likes 0	
Dislikes 0	

Response

Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group

Answer	Yes
Document Name	

Comment

The SPP Standards Review Group ("SSRG") agrees with the proposal to fix the IFRO while the drafting team works on Phase 2. The 2017 FRAA dynamics study and subsequent filing to FERC confirmed the -1,015 MW/0.1Hz IFRO value to be the reliability limit. Without another dynamics study, we do not support the lowering of the IFRO to the values listed in Attachment A. Additionally, the issue may not be the actual determination of the RLPC, but rather how the IFRO is calculated (considering that formula results in an IFRO recommendation below previously established limits).

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

The MRO NSRF agrees with fixing the IFROs in Attachment A during the remainder of Project 2017-01 assuming the SDT is talking about the minor changes that arise from NERC's annual frequency analysis, and not that the SDT is precluding the three step change in the East's IFRO.

Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	
Comment	
LG&E/KU agrees with keeping IFROs as scheduled in Attachment A, but we recommend the Drafting Team specify that IFROs will be as shown in **Table 1** of Attachment A. Additionally, Table 1 should specify the applicable OY for the changes in EI IFRO, rather than the “First, Second, and Final Steps.”	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2, Group Name SRC	
Answer	Yes
Document Name	
Comment	
The SRC agrees with fixing the IFROs in Attachment A during the remainder of Project 2017-01 assuming the SDT is talking about the minor changes that arise from NERC’s annual frequency analysis, and not that the SDT is precluding the three step change in the East’s IFRO.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC) and has one additional comment under item 4	

below.	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ozan Ferrin - Tacoma Public Utilities (Tacoma, WA) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. The SDT is proposing to move items not related to entity compliance from BAL-003-1.1, Attachment A to the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document. Changes to this document will be subject to approval by the NERC Board of Trustees and informational filing to FERC. Do you agree that the SDT's proposed changes are appropriate? If not, please provide an alternative. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes that the IFRO and MDF calculation methodology should be established and detailed in Attachment A so that it is transparent to all parties. The Table 1 of values, that can change yearly, should be moved to another NERC document that is not subject to the NERC standard development process. Any subsequent IFRO and MDF calculation methodology as determined in Phase II of Project 2017-01 should also reside in Attachment A.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
While beneficial, the procedure document is not sufficiently complete to be considered a procedure. For completeness' sake, the document should contain a revision record, a section covering rolls and responsibilities, and a section describing the methods that should be used to limit the reduction of IFRO. While we agree with keeping the document outside the defined process for standards development and balloting, we believe there should still be a rigorous mechanism for when changes are developed, proposed, and potentially adopted. More specificity is needed in "Chapter 1: Event Selection Process", as it is not clear what criteria is to be used going forward. The statistical relevance driver used results in a large portion of events selected for the EI, where neither the BAs nor the GO/GOP has had any appreciable influence on frequency response. Our comments in this section notwithstanding, we acknowledge that our concerns may eventually be addressed as part of Phase 2.	
Likes 0	
Dislikes 0	
Response	

Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC) and has one additional comment under item 4 below.	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the moving of these administrative items from the standard to the procedure. AZPS asks the Drafting Team to provide clarity on whether Form 2s are also required to be submitted and if so, please include in the procedure. And as mentioned in response to Question 2, please consider moving the table which demonstrates what the currently calculated values are for RLPC, CLR, and IFRO for the coming years out of the standard and into the procedure as well.	
Likes 0	
Dislikes 0	
Response	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
IID believes that this will simply the FRO and FR settings. Indirectly this can also reduce risk when the FRM is reduced dramatically.	
Likes 0	
Dislikes 0	
Response	

Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	
Comment	
LG&E/KU recommends that the Event Selection Criteria include a consideration for load level at the time of the event. Load provides a frequency response benefit that is proportional to the amount and type of load on-line at the time of the event. Therefore, events occurring during light load realize less of this benefit, and such events will exhibit greater volatility in frequency excursions. Selection of too many events during low load periods can skew the results, which will not provide the most accurate view of an interconnection's "normal" FR capability.	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2, Group Name SRC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ozan Ferrin - Tacoma Public Utilities (Tacoma, WA) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

4. Please provide any additional comments for the SDT to consider that have not already been provided in the questions above.

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
The original SAR that brought about the SDT discussed the need for application of governor standards to the GO's. NV Energy recognizes that no reference to this item from the SAR is addressed in Phase 1, or in the proposed changes coming in Phase 2. In its Notice of Proposed Rulemaking (NOPR) on Primary Frequency Response (Docket No. RM16-6-000), FERC stated that proposed modifications to Generator Interconnection Agreements for both large and small generating facilities (both synchronous and non-synchronous) would require new generators to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection. FERC recognized that "[w]hile NERC Reliability Standard BAL-003-1.1 establishes requirements for balancing authorities, it does not include any requirements for individual generator owners or operators," and that "[w]hen considered in aggregate, the primary frequency response provided by generators within an Interconnection has a significant impact on the overall frequency response." NV Energy would like to see additional information from the SDT on why this FERC-identified, and SAR objective, is not currently being addressed in either Phase of the revisions to BAL-003.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	
We believe adding 1) a revision history section to the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard and 2) an informative section describing the method that industry receives the information regarding the changes associated with the procedure or RLPC; would improve the overall effectiveness of this procedure.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	

Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
Duke Energy's "Affirmative" vote for Phase 1 of this Project, is based in large part on our support for the continuation of the Project into Phase 2. We appreciate the work performed by the drafting team thus far, and look forward to Phase 2 of the Project.	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	
Document Name	
Comment	
LG&E/KU believes the Frequency Response Standard Background Document goes beyond explaining "the rationale and considerations for the Requirements of this standard and their associated compliance information." As written, the Background Document promotes the concept of frequency responsive reserves, as detailed in the Good Practices and Tools section. We believe that the Drafting team should remove the Good Practices and Tools section from the Background Document, as it strays from the document's intended purpose. If necessary, the Good Practices and Tools section could be included in the Reliability Guideline Primary Frequency Control.	
Likes 0	
Dislikes 0	
Response	

Diana Torres - Imperial Irrigation District - 1,3,5,6	
Answer	
Document Name	
Comment	
IID, a relatively small BA in the western interconnection does not see major issues with the proposed SDT changes.	
Likes 0	
Dislikes 0	
Response	

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	
Document Name	
Comment	
PJM thanks and supports the BAL-003-1 Standard Drafting Team's draft revisions to BAL-003-1 in Phase 1; and supports the development of the Standards Authorization Request in Phase 2 information as it pertains to correcting the applicable entity that controls and provides frequency response, and other related information. PJM believes generators providing primary frequency response is an essential reliability need for both real-time and restoration conditions. A generator requirement across the Interconnections can ensure the necessary frequency response. PJM conducted a stakeholder process in 2018 for primary frequency response requirements for generators, however was unable to reach stakeholder consensus. One of the concerns raised from our members was that this is an Interconnection product, and as such PJM encourages NERC to continue this discussion in the Standard Drafting Team process.	
Likes 0	
Dislikes 0	
Response	

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
Any further reduction in frequency response is not acceptable.	
Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
AZPS would like to point out that the changes made to the Violation Severity Levels for R1 unintentionally created multiple outcomes based on certain criteria. The way the Moderate, High, and Severe VSLs are described, a Balancing Authority could have a less negative FRM than its FRO reflected in MW/0.1 Hz that qualifies for multiple levels. For example, if a BA had a deficiency between 31-45 MW, it could qualify as both Moderate and High. Deficiencies of 46 MW or greater could qualify as both Moderate and Severe. The use of the word “or” allows for this dilemma. AZPS does not recommend removing the word “or,” but rather completing the ranges with the levels to eliminate this confusion.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
BPA noticed in review of the revised standard that the Violation Severity Levels are less restrictive. This change was not in the list of modifications at the start of this document. BPA cannot agree with less restrictive VSLs in combination with the current median FRM score utilized for compliance. BPA feels that if an entity does not meet the median it should be at the severe VSL. However, in order to move onto Phase II of the 2017-01 project, BPA suggests the following approach until Phase II can be completed Alternative Approach: BPA suggests that the VSLs for R1 be made more restrictive. Lower Level between 1% and 5%, moderate 5% to 10%, high 10% to 15% and Severe greater than 15%. In WECC, the majority of selected frequency events have loss of less than 1000 MW with a nadir of 59.9 Hz or greater (less than or equal to 100 mHz deviation.) If an entity cannot comply with the median FRM, that entity has high probability of never being able to respond adequately to an event the size of the RLPC. If multiple entities have an FRM less than the median, the interconnection is at a high risk of underfrequency load shed when a loss as great as the RLPC occurs. Therefore, BPA believes the VSLs must be more restrictive than the proposed to support interconnection reliability.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	

Document Name	
Comment	

Xcel Energy would like to ensure that the proposed change to the C point to 20 seconds instead of 12 seconds (as specified on Page 1 of the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document is consistently changed throughout the document. For example, it is not clear if the language on page 1 in 3b needs modification ("18 seconds"), and page 2 item 5 ("18 seconds").

Also, we would like to understand how proposed changes to the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document will gather input from industry and also any approved changes publicized, if not through the standards process (ie standards development distribution lists).

Likes 0	
Dislikes 0	
Response	

Richard Vine - California ISO - 2

Answer	
Document Name	
Comment	

Table 1, which starts on page 12 and ends on page 13 of the proposed standard reflects a value of 120MW as "Credit for Load Resources" for the Western Interconnection. The California ISO suggests that this number be validated as accurate at this point in time.

Likes 0	
Dislikes 0	
Response	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	
Document Name	
Comment	

SRP supports the proposed revisions and does not have additional comments for the SDT.

Likes 0	
Dislikes 0	
Response	

Consideration of Comments

Project Name:	2017-01 Modifications to BAL-003-1.1
Comment Period Start Date:	12/4/2018
Comment Period End Date:	1/17/2019
Associated Ballots:	2017-01 Modifications to BAL-003-1.1 BAL-003-2 IN 1 ST 2017-01 Modifications to BAL-003-1.1 BAL-003-2 Non-Binding Poll IN 1 NB 2017-01 Modifications to BAL-003-1.1 Implementation Plan IN 1 OT

There were 23 sets of responses, including comments from approximately 93 different people from approximately 69 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Senior Director of Engineering and Standards, Howard Gugel (via email) or at (404) 446-9693.

Questions

1. The SDT proposes to replace Resource Contingency Criteria (RCC) with the Resource Loss Protection Criteria (RLPC). This criterion will be applied consistently across all Interconnections, and is designed to produce adequate reliability for each Interconnection. The RLPC determination methodology is detailed for this posting in the *Resource Loss Protection Criteria* Section of the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document and further in the *Resource Loss Protection Criteria* document. Is this methodology appropriate for determining the magnitude of the resource loss events that each Interconnection should protect against to assure an adequate level of reliability? If not, please provide an alternative proposal and any comments to the *Resource Loss Protection Criteria* document, which has been revised based on industry comment.

Summary Responses:

The SDT received comments regarding the description of the RLPC in the first bullet of Chapter 3 of the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. The commenters questioned the intent of two events that are caused by a single contingency, which would be an N-2. The SDT agreed with the comments made and has modified the language to address the comments received. The bullet now states: “The two largest independent Balancing Contingency Events, each due to a single contingency identified using system models measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)”

The SDT received comments regarding the proposed methodology may not produce consistent results, but does appear to provide a reasonable margin to reduce the potential for triggering UFLS operation due to insufficient frequency response. The comments suggested that the proposed methodology is based-on (as well as highly dependent-on) the current resource mix and configuration. The SDT agrees with the potential concern. Phase II of Project 2017-01 will be evaluating the IFRO methodology and allocation thereof.

The SDT received the comment regarding Page 1 of the RLPC document containing the statement: “The MSSC calculation is done in Real-time operations based on actual system configuration.” The commenter suggested deleting this statement. The RLPC document is a supporting document during development of Phase I. The SDT will addressed this issue in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.

2. The SDT proposes fixing IFROs for a period that will continue until Phase 2 of the Project 2017-01 is completed. Do you agree with keeping IFROs as scheduled in Attachment A during the remainder of Project 2017-01? If you do not agree, please provide an alternative. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

Summary Responses:

The SDT received comments on the newly proposed methodology for IFRO, commenting if it would only be valid to apply until after Phase Two is completed. It was also suggested that leaving the currently-determined values based on the proposed methodology out of the actual standard since all of the contributing elements are subject to change based on the procedure and could quickly become inaccurate. It may be more appropriate to publish the currently determined values in the procedure, which can be updated often as necessary, and not in the standard. In response, the SDT modified the RLPC to provide a bridge until Phase II can evaluate the IFRO methodology in its entirety. The response by the SDT is that BAL-003-2 proposes revisions to *Standard BAL-003-1.1 – Frequency Response and Frequency Bias Setting* that would modify how the IFROs will be determined. NERC staff conducted a study to validate the proposed methodology and will file the study report with FERC. The study report will describe the proposed changes to the method of determining the RLPCs and will outline how those proposed changes would be reflected in the IFROs and how those revised IFROs were tested to assure that those levels of response are adequate to protect the Interconnection. The SDT found the results of the study to be sufficient.

The ERO, in consultation with regional representatives, has established a target reliability criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). Preliminary values are provided below. Certain values are assessed annually according to the methodology which is detailed in the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.
The SDT has updated the IFRO values in the Table in Attachment A, and the MDF values reflect those used in the Table 2.4 of the 2017 FRAA report. The SDT disagrees that the IFRO would need to revert back to the previous value if the Interconnection FRM declines by more than 10%. The SDT believes there is sufficient margin for the near term, but will continue to evaluate this issue in Phase II.

The SDT believes the existing studies and the 2017 FRAA informational filing to FERC clearly demonstrate the sufficiency of frequency response in the Interconnection in the event of a MW loss on the level of the RLPC. Nevertheless, NERC will continue to assess the IFRO in the FRAA under the constructs of the proposed BAL-003-2 standard. The SDT will continue to review this as part of Phase II.

The SDT received a comment of agreement in regards to fixing the IFROs in Attachment A during the remainder of Project 2017-01, assuming the SDT is talking about the minor changes that arise from NERC's annual frequency analysis, and not that the SDT is precluding the three step change in the East's IFRO. In response, the SDT noted that it is not precluding the three-step change.

A comment received recommend that the Drafting Team specify that IFROs will be as shown in **Table 1** of Attachment A; and that Table 1 should specify the applicable OY for the changes in EI IFRO, rather than the "First, Second, and Final Steps." Due to the process under which NERC operates, the SDT has updated the language to "First-step target IFRO, Second-step target IFRO, and Final target IFRO."

3. The SDT is proposing to move items not related to entity compliance from BAL-003-1.1, Attachment A to the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document. Changes to this document will be subject to approval by the NERC Board of Trustees and informational filing to FERC. Do you agree that the SDT's proposed changes are appropriate? If not, please provide an alternative. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

Summary Responses:

ERCOT: The SDT updated Table 1.1 in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document for the ERCOT Interconnection. ERCOT presented this update to Table 1.1 at a public meeting of the Resources Subcommittee, conducted on April 20, 2019. No concerns were raised by the Reliability Subcommittee. The updated Table 1.1 for the ERCOT Interconnection captures at least minimum 20 events each annually, using the current Event Selection criteria in 2018 for ERCOT resulted in selection of only five events.

A comment was received that, while beneficial, the procedure document is not sufficiently complete to be considered a procedure. For completeness' sake, the document should contain a revision record, a section covering rolls and responsibilities, and a section describing the methods that should be used to limit the reduction of IFRO. While the commenter agreed with keeping the document outside the defined process for standards development and balloting, they noted that there should still be a rigorous mechanism for when changes are developed, proposed, and potentially adopted.

The SDT will pass your comment on to NERC staff for them to decide the changes in formatting for the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. The SDT has recommended that a version number and date for the document be added. The SDT agrees that the Event Selection Process will be reviewed in Phase II.

A commenter agreed with the moving of these administrative items from the standard to the procedure, but asks the SDT to provide clarity on whether Form 2s are also required to be submitted; and, if so, to include that in the procedure. In response, the SDT refers the commenter to Attachment A of the standard (Page 13), as it states: "All events listed on FRS Form 1 need to be included in the annual submission of FRS Forms 1 and 2." Since the IFRO directly impacts an entity's compliance obligation, the drafting team recommends that it stay in Attachment A.

A commenter recommended that the Event Selection Criteria include a consideration for load level at the time of the event; that load provides a frequency response benefit that is proportional to the amount and type of load on-line at the time of the event. Therefore, events occurring during light load realize less of this benefit, and such events will exhibit greater volatility in frequency excursions. Selection of too many events during low load periods can skew the results, which will not provide the most accurate view of an interconnection's "normal" FR capability. In response, the SDT, based on the data reviewed, determined that the events occurring during lower load times in an interconnection are the events that could potentially be more of a risk to reliability. Therefore, the process proposed is silent on the mix of events to be used for the compliance calculation. Instead, the main driver of the list is the depth of the frequency excursion rather than trying to find events in a particular part of the day/week/season.

4. Please provide any additional comments for the SDT to consider that have not already been provided in the questions above.

Summary Responses: A comment received stated that the original SAR that brought about the SDT discussed the need for application of governor standards to the GO's. In its Notice of Proposed Rulemaking (NOPR) on Primary Frequency Response (Docket No. RM16-6-000), FERC stated that proposed modifications to Generator Interconnection Agreements for both large and small generating facilities (both synchronous and non-synchronous) would require new generators to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection. FERC recognized that "[w]hile NERC Reliability Standard BAL-003-1.1 establishes requirements for balancing authorities, it does not include any requirements for individual generator owners or operators," and that "[w]hen considered in aggregate, the primary frequency response provided by generators within an Interconnection has a significant impact on the overall frequency response." The commenter requested to see additional information from the SDT on why this FERC-identified, and SAR objective, is not currently being addressed in either Phase of the revisions to BAL-003.

In response, the SAR approved by the Standards Committee, under which this drafting team is working, states in the second bullet under Phase II "Although Balancing Authorities (BAs) and FRSGs are responsible for coordination and/or management of Frequency Response from both resources and loads, response from resources is not addressed. The review should determine if additional reliability entities should have responsibility (e.g., Generator Operators (GOPs)) for provision of generator governor response; and…" Therefore, the SDT will discuss and potentially recommend additional requirements in the future related to other entities. The SDT adds that it is unlikely to recommend removing the existing requirement related to BAs and FRSGs due to the reasoning stated in the SAR. Future postings for comments related to BAL-003 will allow for industry feedback on this issue.

One commenter stated that the Frequency Response Standard Background Document goes beyond explaining "the rationale and considerations for the Requirements of this standard and their associated compliance information." That, as written, the Background Document promotes the concept of frequency responsive reserves, as detailed in the Good Practices and Tools section.

The SDT posted the Background Document (which was drafted in 2012) as part of developing BAL-003-1 for reference only. This drafting team is not proposing any changes to that document.

A comment was received that Table 1 of the proposed standard reflects a value of 120MW as "Credit for Load Resources" for the Western Interconnection and suggested that this number be validated as accurate at this point in time. In response, the SDT has removed the Credit for Load Resources (CLR) in the Western Interconnection.

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Powert	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO

					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
PPL - Louisville Gas and Electric Co.	Devin Shines	3,5,6	RF,SERC	Louisville Gas and Electric Company and Kentucky Utilities Company	Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					JULIE HOSTRANDER	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
Southwest Power Pool, Inc. (RTO)	Jim Williams	2	MRO,SERC	SPP Standards Review Group	Jim Williams	SPP	2	MRO
					Shannon Mickens	SPP	2	MRO
ACES Power Marketing	Jodirah Green	6	NA - Not Applicable	ACES Standard Collaborations	John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC

					Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3,6	Texas RE
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Jenny Knernschield	Old Dominion Electric Cooperative	3,4	SERC
DTE Energy - Detroit Edison Company	Karie Barczak	3		DTE Energy - DTE Electric	Jeffrey Depriest	DTE Energy - DTE Electric	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
PJM Interconnection, L.L.C.	Mark Holman	2		SRC	Brandon Gleason	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	SERC

					Ali Miremadi	California ISO	2	WECC
					Helen Laines	Independent Electric System Operator	2	NPCC
					Kathleen Goodman	ISO New England	2	NPCC
					Mark Holman	PJM Interconnection	2	RF
					Terry Bilke	Midcontinent Independent System Operator	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC
Manitoba Hydro	Mike Smith	1		Manitoba Hydro	Yuguang Xiao	Manitoba Hydro	5	MRO
					Karim Abdel-Hadi	Manitoba Hydro	3	MRO
					Blair Mukanik	Manitoba Hydro	6	MRO
					Mike Smith	Manitoba Hydro	1	MRO
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC

					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Jones	National Grid	3	NPCC
					Sean Cavote	PSEG	4	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					David Kiguel	Independent	NA - Not Applicable	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Caroline Dupuis	Hydro Quebec	1	NPCC

					Chantal Mazza	Hydro Quebec	2	NPCC
					Michael Forte	Con Edison	1	NPCC
					Laura McLeod	NB Power Corporation	5	NPCC
					Nick	Kowalczyk	1	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					John Hastings	National Grid	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Sofia Gadea-Omelchenko	Con Edison	5	NPCC
					Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

					Shivaz Chopra	New York Power Authority	5	NPCC

1. The SDT proposes to replace Resource Contingency Criteria (RCC) with the Resource Loss Protection Criteria (RLPC). This criterion will be applied consistently across all Interconnections, and is designed to produce adequate reliability for each Interconnection. The RLPC determination methodology is detailed for this posting in the *Resource Loss Protection Criteria* Section of the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document and further in the *Resource Loss Protection Criteria* document. Is this methodology appropriate for determining the magnitude of the resource loss events that each Interconnection should protect against to assure an adequate level of reliability? If not, please provide an alternative proposal and any comments to the *Resource Loss Protection Criteria* document, which has been revised based on industry comment.

Summary Responses:

The SDT received comments regarding the description of the RLPC in the first bullet of Chapter 3 of the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. The commenters questioned the intent of two events that are caused by a single contingency, which would be an N-2. The SDT agreed with the comments made and has modified the language to address the comments received. The bullet now states: "The two largest independent Balancing Contingency Events, each due to a single contingency identified using system models measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)"

The SDT received comments regarding the proposed methodology may not produce consistent results, but does appear to provide a reasonable margin to reduce the potential for triggering UFLS operation due to insufficient frequency response. The comments suggested that the proposed methodology is based-on (as well as highly dependent-on) the current resource mix and configuration. The SDT agrees with the potential concern. Phase II of Project 2017-01 will be evaluating the IFRO methodology and allocation thereof.

The SDT received the comment regarding Page 1 of the RLPC document containing the statement: "The MSSC calculation is done in Real-time operations based on actual system configuration." The commenter suggested deleting this statement. The RLPC document is a supporting document during development of Phase I. The SDT will addressed this issue in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	
Comment	

AZPS appreciates the changes that were made that largely address our concerns and many others in the industry. AZPS now largely supports the RLPC with one important distinction. We believe the description of the RLPC is inaccurately described in the first bullet of Chapter 3 of the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.

"The two largest Balancing Contingency Events due to a single contingency identified using system models in terms of loss measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.) "

We do not believe the intent is two events that are caused by a single contingency, which would be an N-2. Perhaps a better way to state what is intended is the language used in the proposed BAL-003-2, "the two largest potential Balancing Contingency Events that exist within a Balancing Authority identified using system models in terms of loss measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)"

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT has modified the language to address your comment: "The two largest independent Balancing Contingency Events, each due to a single contingency, identified using system models measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)"

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

The proposed methodology does appear to produce consistent results; however it represents a resource loss that may not actually manifest itself in practice. It does appear to provide a reasonable margin to reduce the potential for triggering UFLS operation due to insufficient frequency response. We appreciate the efforts of the SDT, however we believe it needs to be recognized that the proposed methodology is based-on (as well as highly dependent-on) the current resource mix and configuration.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees with the potential concern. Phase II will be evaluating the IFRO methodology and allocation thereof.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC) and has one additional comment under item 4 below.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
BPA supports replacing the Resource Contingency Criteria (RCC) with the Resource Loss Protection Criteria (RLPC). BPA agrees this methodology is appropriate for determining the magnitude of the resource loss events that each Interconnection should protect against to assure an adequate level of reliability. BPA suggests that the SDT review the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* to ensure that the language regarding RLPC matches the *Resource Loss Protection Criteria* document.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has reviewed the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* and verified that the appropriate language is there.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	
Comment	
Louisville Gas and Electric Company and Kentucky Uitilities Company (LG&E/KU) generally agree with the proposed methodology. However, Page 1 of the RLPC document contains the statement: “The MSSC calculation is done in Real-time operations based on actual system configuration.” However, not every BA or RSG determines MSSC in real time – many do not. We recommend the SDT delete this statement for accuracy.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT will address this in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
We believe replacing the RCC with the RLPC will bring consistency across all interconnections and will eliminate the need of having a higher expectation from the Eastern Interconnection. Additionally, revising the verbiage associated with the MSSC, as one the basis for IFRO, has improved the overall technicality of the RPLC.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Holman - PJM Interconnection, L.L.C. - 2, Group Name SRC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ozan Ferrin - Tacoma Public Utilities (Tacoma, WA) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

2. The SDT proposes fixing IFROs for a period that will continue until Phase 2 of the Project 2017-01 is completed. Do you agree with keeping IFROs as scheduled in Attachment A during the remainder of Project 2017-01? If you do not agree, please provide an alternative. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

Summary Responses:

The SDT received comments on the newly proposed methodology for IFRO, commenting if it would only be valid to apply until after Phase Two is completed. It was also suggested that leaving the currently-determined values based on the proposed methodology out of the actual standard since all of the contributing elements are subject to change based on the procedure and could quickly become inaccurate. It may be more appropriate to publish the currently determined values in the procedure, which can be updated often as necessary, and not in the standard. In response, the SDT modified the RLPC to provide a bridge until Phase II can evaluate the IFRO methodology in its entirety. The response by the SDT is that BAL-003-2 proposes revisions to *Standard BAL-003-1.1 – Frequency Response and Frequency Bias Setting* that would modify how the IFROs will be determined. NERC staff conducted a study to validate the proposed methodology and will file the study report with FERC. The study report will describe the proposed changes to the method of determining the RLPCs and will outline how those proposed changes would be reflected in the IFROs and how those revised IFROs were tested to assure that those levels of response are adequate to protect the Interconnection. The SDT found the results of the study to be sufficient.

The ERO, in consultation with regional representatives, has established a target reliability criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). Preliminary values are provided below. Certain values are assessed annually according to the methodology which is detailed in the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.
The SDT has updated the IFRO values in the Table in Attachment A, and the MDF values reflect those used in the Table 2.4 of the 2017 FRAA report. The SDT disagrees that the IFRO would need to revert back to the previous value if the Interconnection FRM declines by more than 10%. The SDT believes there is sufficient margin for the near term, but will continue to evaluate this issue in Phase II.

The SDT believes the existing studies and the 2017 FRAA informational filing to FERC clearly demonstrate the sufficiency of frequency response in the Interconnection in the event of a MW loss on the level of the RLPC. Nevertheless, NERC will continue to assess the IFRO in the FRAA under the constructs of the proposed BAL-003-2 standard. The SDT will continue to review this as part of Phase II.

The SDT received a comment of agreement in regards to fixing the IFROs in Attachment A during the remainder of Project 2017-01, assuming the SDT is talking about the minor changes that arise from NERC's annual frequency analysis, and not that the SDT is precluding the three step change in the East's IFRO. In response, the SDT noted that it is not precluding the three-step change.

A comment received recommend that the Drafting Team specify that IFROs will be as shown in **Table 1** of Attachment A; and that Table 1 should specify the applicable OY for the changes in EI IFRO, rather than the "First, Second, and Final Steps." Due to the process under which NERC operates, the SDT has updated the language to "First-step target IFRO, Second-step target IFRO, and Final target IFRO."

Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	

AZPS questions the logic that the newly proposed methodology for IFRO would only be valid to apply this one time until after Phase Two is completed. If it is believed that this IFRO methodology is technically valid, then it should be valid until an approved alternative is determined and approved. AZPS would also suggest leaving the currently determined values based on this methodology out of the actual standard since all of the contributing elements are subject to change based on the procedure and could quickly become inaccurate. It may be more appropriate to publish the currently determined values in the procedure, which can be updated often as necessary, and not in the standard.

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT modified the RLPC to provide a bridge until Phase II can evaluate the IFRO methodology in its entirety. The response by the SDT is that BAL-003-2 proposes revisions to *Standard BAL-003-1.1 – Frequency Response and Frequency Bias Setting* that would modify how the IFROs will be determined. NERC staff conducted a study to validate the proposed methodology and will file the study report with FERC. The study report will describe the proposed changes to the method of determining the RLPCs and will outline how those

proposed changes would be reflected in the IFROs and how those revised IFROs were tested to assure that those levels of response are adequate to protect the Interconnection. The SDT found the results of the study to be sufficient.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

There are several reasons that BPA cannot agree with keeping IFROs as scheduled in the revised Attachment A during the remainder of Project 2017-01.

-
    - The IFRO First Step for the Western Interconnection includes a Load Credit of 120 MW. There is no Load Credit for a PDCI RAS event.

Alternative approach: BPA asks that the First Step for WECC be recalculated without the Load Credit applied.

-
    - It is apparent that the First Step IFRO in the BAL-003 redline was calculated as (RLPC - Load Credit) / 10 * MDF

However, it is not apparent how the Max Delta Frequency (MDF) was determined since the tables with subcomponents such as the CBR (C to B ratio) are missing from the standard or a supporting document. The standard does say: "Detailed descriptions of the calculations used in Table 1 below are defined in the Procedure for *ERO Support of Frequency Response and Frequency Bias Setting Standard*." But the *ERO Support of Frequency Response and Frequency Bias Setting Standard* does not detail at all how the calculations used in Table 1 are defined, because the calculations were removed from that document.

Alternative approach: BPA recommends that the methodology for determining IFRO and MDF be detailed in Attachment A and that Table 1 be moved to a NERC document that can be updated yearly. The IFRO and MDF are key components of the current standard and the methodology

for calculating it must be in Attachment A so that it cannot change without industry vote and FERC approval. BPA supports a change in the IFRO methodology through Phase II of Project 2017-01, at which point Attachment A should be updated. • o The revised standard states that "**To reduce risk, the Eastern Interconnection IFRO will be stepped down annually from the 2017 value of -1,015 MW/0.1 Hz in -100 MW/0.1 Hz increments. If during the step down process, Interconnection Frequency Response Measure (FRM) declines by more than 10% percent, the ERO will halt the reduction in IFRO until such times that a determination can be made as to the cause of the degradation." BPA believes that this is not adequate for reliability. Alternative approach: BPA recommends that if the Interconnection Frequency Response Measure (FRM) declines by more than 10% percent, the ERO raise the IFRO back to the previous step.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has removed the Credit for Load Resources (CLR) in the Western Interconnection. For Phase I, the SDT set a fixed MDF to provide a bridge until Phase II can evaluate the IFRO methodology in its entirety. The SDT has updated the IFRO values in the Table in Attachment A, and the MDF values reflect those used in the Table 2.4 of the 2017 FRAA report. The SDT modified the RLPC to provide a bridge until Phase II can evaluate the IFRO methodology in its entirety. The response by the SDT is that BAL-003-2 proposes revisions to *Standard BAL-003-1.1 – Frequency Response and Frequency Bias Setting* that would modify how the IFROs will be determined. NERC staff conducted a study to validate the proposed methodology and will file the study report with FERC. The study report will describe the proposed changes to the method of determining the RLPCs and will outline how those proposed changes would be reflected in the IFROs and how those revised IFROs were tested to assure that those levels of response are adequate to protect the Interconnection. The SDT found the results of the study to be sufficient. The SDT disagrees that the IFRO would need to revert back to the previous value if the Interconnection FRM declines by more than 10%. The SDT believes there is sufficient margin for the near term, but will continue to evaluate this issue in Phase II.	

Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
The SPP Standards Review Group ("SSRG") agrees with the proposal to fix the IFRO while the drafting team works on Phase 2. The 2017 FRAA dynamics study and subsequent filing to FERC confirmed the -1,015 MW/0.1Hz IFRO value to be the reliability limit. Without another dynamics study, we do not support the lowering of the IFRO to the values listed in Attachment A. Additionally, the issue may not be the actual determination of the RLPC, but rather how the IFRO is calculated (considering that formula results in an IFRO recommendation below previously established limits).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. BAL-003-2 proposes revisions to *Standard BAL-003-1.1 – Frequency Response and Frequency Bias Setting* that would modify how the IFROs will be determined. NERC staff conducted a study to validate the proposed methodology and will file the study report with FERC. The study report will describe the proposed changes to the method of determining the RLPCs and will outline how those proposed changes would be reflected in the IFROs and how those revised IFROs were tested to assure that those levels of response are adequate to protect the Interconnection. The SDT found the results of the study to be sufficient. The SDT will continue to review this as part of Phase II.	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	

The MRO NSRF agrees with fixing the IFROs in Attachment A during the remainder of Project 2017-01 assuming the SDT is talking about the minor changes that arise from NERC's annual frequency analysis, and not that the SDT is precluding the three step change in the East's IFRO.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT is not precluding the three-step change.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	Yes
Document Name	
Comment	
LG&E/KU agrees with keeping IFROs as scheduled in Attachment A, but we recommend the Drafting Team specify that IFROs will be as shown in **Table 1** of Attachment A. Additionally, Table 1 should specify the applicable OY for the changes in EI IFRO, rather than the "First, Second, and Final Steps."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has updated the language to "First-step target IFRO, Second-step target IFRO, and Final target IFRO." These values are evaluated annually for changes in each Interconnection. To reduce risk, the Eastern Interconnection IFRO will be stepped down annually from the 2017 value of -1,015 MW/0.1 Hz in -100 MW/0.1 Hz increments. If during the step down process, Interconnection Frequency Response Measure (FRM) declines by more than 10 percent, the ERO will halt the reduction in IFRO until such time that a determination can be made as to the cause of the degradation.	

Mark Holman - PJM Interconnection, L.L.C. - 2, Group Name SRC	
Answer	Yes
Document Name	
Comment	
The SRC agrees with fixing the IFROs in Attachment A during the remainder of Project 2017-01 assuming the SDT is talking about the minor changes that arise from NERC's annual frequency analysis, and not that the SDT is precluding the three step change in the East's IFRO.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT is not precluding the three-step change.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC) and has one additional comment under item 4 below.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ozan Ferrin - Tacoma Public Utilities (Tacoma, WA) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

3. The SDT is proposing to move items not related to entity compliance from BAL-003-1.1, Attachment A to the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document. Changes to this document will be subject to approval by the NERC Board of Trustees and informational filing to FERC. Do you agree that the SDT's proposed changes are appropriate? If not, please provide an alternative. Or, if you agree but have comments or suggestions on the SDT's recommendation, please provide your explanation and suggested language.

Summary Responses:

The SDT updated Table 1.1 in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document for the ERCOT Interconnection. ERCOT presented this update to Table 1.1 at a public meeting of the Resources Subcommittee, conducted on April 20, 2019. No concerns were raised by the Reliability Subcommittee. The updated Table 1.1 for the ERCOT Interconnection captures at least minimum 20 events each annually, using the current Event Selection criteria in 2018 for ERCOT resulted in selection of only five events.

A comment was received that, while beneficial, the procedure document is not sufficiently complete to be considered a procedure. For completeness' sake, the document should contain a revision record, a section covering rolls and responsibilities, and a section describing the methods that should be used to limit the reduction of IFRO. While the commenter agreed with keeping the document outside the defined process for standards development and balloting, they noted that there should still be a rigorous mechanism for when changes are developed, proposed, and potentially adopted.

The SDT will pass your comment on to NERC staff for them to decide the changes in formatting for the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. The SDT has recommended that a version number and date for the document be added. The SDT agrees that the Event Selection Process will be reviewed in Phase II.

A commenter agreed with the moving of these administrative items from the standard to the procedure, but asks the SDT to provide clarity on whether Form 2s are also required to be submitted; and, if so, to include that in the procedure. In response, the SDT refers the commenter to Attachment A of the standard (Page 13), as it states: "All events listed on FRS Form 1 need to be included in the annual submission of FRS Forms 1 and 2." Since the IFRO directly impacts an entity's compliance obligation, the drafting team recommends that it stay in Attachment A.

A commenter recommended that the Event Selection Criteria include a consideration for load level at the time of the event; that load provides a frequency response benefit that is proportional to the amount and type of load on-line at the time of the event. Therefore, events occurring during light load realize less of this benefit, and such events will exhibit greater volatility in frequency excursions. Selection of too many events during low load periods can skew the results, which will not provide the most accurate view of an interconnection's "normal" FR capability. In response, the SDT, based on the data reviewed, determined that the events occurring during lower load times in an interconnection are the events that could potentially be more of a risk to reliability. Therefore, the process proposed is silent on the mix of events to be used for the compliance calculation. Instead, the main driver of the list is the depth of the frequency excursion rather than trying to find events in a particular part of the day/week/season.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes that the IFRO and MDF calculation methodology should be established and detailed in Attachment A so that it is transparent to all parties. The Table 1 of values, that can change yearly, should be moved to another NERC document that is not subject to the NERC standard development process. Any subsequent IFRO and MDF calculation methodology as determined in Phase II of Project 2017-01 should also reside in Attachment A.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes that the modifications made are appropriate for Phase I.	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

While beneficial, the procedure document is not sufficiently complete to be considered a procedure. For completeness' sake, the document should contain a revision record, a section covering rolls and responsibilities, and a section describing the methods that should be used to limit the reduction of IFRO. While we agree with keeping the document outside the defined process for standards development and balloting, we believe there should still be a rigorous mechanism for when changes are developed, proposed, and potentially adopted. More specificity is needed in "Chapter 1: Event Selection Process", as it is not clear what criteria is to be used going forward. The statistical relevance driver used results in a large portion of events selected for the EI, where neither the BAs nor the GO/GOP has had any appreciable influence on frequency response. Our comments in this section notwithstanding, we acknowledge that our concerns may eventually be addressed as part of Phase 2.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. The SDT will pass your comment on to NERC staff for them to decide the changes in formatting for the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.* The SDT will pass your comment on to NERC staff for them to decide the changes in formatting for the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. he SDT has recommended that a version number and date for the document be added. The SDT agrees that the Event Selection Process will be reviewed in Phase II.

Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	

The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC) and has one additional comment under item 4 below.

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the moving of these administrative items from the standard to the procedure. AZPS asks the Drafting Team to provide clarity on whether Form 2s are also required to be submitted and if so, please include in the procedure. And as mentioned in response to Question 2, please consider moving the table which demonstrates what the currently calculated values are for RLPC, CLR, and IFRO for the coming years out of the standard and into the procedure as well.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. In Attachment A, on Page 13 of 15 of the standard, it states: “All events listed on FRS Form 1 need to be included in the annual submission of FRS Forms 1 and 2.” Since the IFRO directly impacts an entity’s compliance obligation, the drafting team recommends that it stay in Attachment A. Please see response to Question 2.	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	

IID believes that this will simply the FRO and FR settings. Indirectly this can also reduce risk when the FRM is reduced dramatically.

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company

Answer	Yes
Document Name	

Comment

LG&E/KU recommends that the Event Selection Criteria include a consideration for load level at the time of the event. Load provides a frequency response benefit that is proportional to the amount and type of load on-line at the time of the event. Therefore, events occurring during light load realize less of this benefit, and such events will exhibit greater volatility in frequency excursions. Selection of too many events during low load periods can skew the results, which will not provide the most accurate view of an interconnection's "normal" FR capability.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Based on the data reviewed, the events occurring during lower load times in an interconnection are the events that could potentially be more of a risk to reliability. Therefore, the process proposed is silent on the mix of events to be used for the compliance calculation. Instead, the main driver of the list is the depth of the frequency excursion rather than trying to find events in a particular part of the day/week/season.

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your response.	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Mark Holman - PJM Interconnection, L.L.C. - 2, Group Name SRC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Ozan Ferrin - Tacoma Public Utilities (Tacoma, WA) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your response.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your response.	
Jim Williams - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	

4. Please provide any additional comments for the SDT to consider that have not already been provided in the questions above.

Summary Responses:

A comment received stated that the original SAR that brought about the SDT discussed the need for application of governor standards to the GO's. In its Notice of Proposed Rulemaking (NOPR) on Primary Frequency Response (Docket No. RM16-6-000), FERC stated that proposed modifications to Generator Interconnection Agreements for both large and small generating facilities (both synchronous and non-synchronous) would require new generators to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection. FERC recognized that "[w]hile NERC Reliability Standard BAL-003-1.1 establishes requirements for balancing authorities, it does not include any requirements for individual generator owners or operators," and that "[w]hen considered in aggregate, the primary frequency response provided by generators within an Interconnection has a significant impact on the overall frequency response." The commenter requested to see additional information from the SDT on why this FERC-identified, and SAR objective, is not currently being addressed in either Phase of the revisions to BAL-003.

In response, the SAR approved by the Standards Committee, under which this drafting team is working, states in the second bullet under Phase II "Although Balancing Authorities (BAs) and FRSGs are responsible for coordination and/or management of Frequency Response from both resources and loads, response from resources is not addressed. The review should determine if additional reliability entities should have responsibility (e.g., Generator Operators (GOPs)) for provision of generator governor response; and…" Therefore, the SDT will discuss and potentially recommend additional requirements in the future related to other entities. The SDT adds that it is unlikely to recommend removing the existing requirement related to BAs and FRSGs due to the reasoning stated in the SAR. Future postings for comments related to BAL-003 will allow for industry feedback on this issue.

One commenter stated that the Frequency Response Standard Background Document goes beyond explaining “the rationale and considerations for the Requirements of this standard and their associated compliance information.” That, as written, the Background Document promotes the concept of frequency responsive reserves, as detailed in the Good Practices and Tools section.

The SDT posted the Background Document (which was drafted in 2012) as part of developing BAL-003-1 for reference only. This drafting team is not proposing any changes to that document.

A comment was received that Table 1 of the proposed standard reflects a value of 120MW as “Credit for Load Resources” for the Western Interconnection and suggested that this number be validated as accurate at this point in time. In response, the SDT has removed the Credit for Load Resources (CLR) in the Western Interconnection.

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	

The original SAR that brought about the SDT discussed the need for application of governor standards to the GO’s. NV Energy recognizes that no reference to this item from the SAR is addressed in Phase 1, or in the proposed changes coming in Phase 2. In its Notice of Proposed Rulemaking (NOPR) on Primary Frequency Response (Docket No. RM16-6-000), FERC stated that proposed modifications to Generator Interconnection Agreements for both large and small generating facilities (both synchronous and non-synchronous) would require new generators to install, maintain, and operate equipment capable of providing primary frequency response as a condition of interconnection. FERC recognized that “[w]hile NERC Reliability Standard BAL-003-1.1 establishes requirements for balancing authorities, it does not include any requirements for individual generator owners or operators,” and that “[w]hen considered in aggregate, the primary frequency response provided by generators within an Interconnection has a significant impact on the overall frequency response.” NV Energy would like to see additional information from the SDT on why this FERC-identified, and SAR objective, is not currently being addressed in either Phase of the revisions to BAL-003.

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SAR approved by the Standards Committee under which this drafting team is working states in the second bullet under Phase II "Although Balancing Authorities (BAs) and FRSGs are responsible for coordination and/or management of Frequency Response from both resources and loads, response from resources is not addressed. The review should determine if additional reliability entities should have responsibility (e.g., Generator Operators (GOPs)) for provision of generator governor response; and…" Therefore, the SDT will discuss and potentially recommend additional requirements in the future related to other entities. The SDT adds that it is unlikely to recommend removing the existing requirement related to BAs and FRSGs due to the reasoning stated in the SAR. Future postings for comments related to BAL-003 will allow for industry feedback on this issue.	
Jodirah Green - ACES Power Marketing - 6, Group Name ACES Standard Collaborations	
Answer	
Document Name	
Comment	
We believe adding 1) a revision history section to the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard and 2) an informative section describing the method that industry receives the information regarding the changes associated with the procedure or RLPC; would improve the overall effectiveness of this procedure.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT will pass your comment on to NERC staff for them to decide the changes in formatting for the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	

Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
Duke Energy's "Affirmative" vote for Phase 1 of this Project, is based in large part on our support for the continuation of the Project into Phase 2. We appreciate the work performed by the drafting team thus far, and look forward to Phase 2 of the Project.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
Answer	
Document Name	

Comment	
LG&E/KU believes the Frequency Response Standard Background Document goes beyond explaining "the rationale and considerations for the Requirements of this standard and their associated compliance information." As written, the Background Document promotes the concept of frequency responsive reserves, as detailed in the Good Practices and Tools section. We believe that the Drafting team should remove the Good Practices and Tools section from the Background Document, as it strays from the document's intended purpose. If necessary, the Good Practices and Tools section could be included in the Reliability Guideline Primary Frequency Control.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The Background Document was drafted in 2012 as part of developing BAL-003-1 and posted under this project for reference only. This drafting team is not proposing any changes to that document.	
Diana Torres - Imperial Irrigation District - 1,3,5,6	
Answer	
Document Name	
Comment	
IID, a relatively small BA in the western interconnection does not see major issues with the proposed SDT changes.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	

Answer	
Document Name	
Comment	

PJM thanks and supports the BAL-003-1 Standard Drafting Team's draft revisions to BAL-003-1 in Phase 1; and supports the development of the Standards Authorization Request in Phase 2 information as it pertains to correcting the applicable entity that controls and provides frequency response, and other related information. PJM believes generators providing primary frequency response is an essential reliability need for both real-time and restoration conditions. A generator requirement across the Interconnections can ensure the necessary frequency response. PJM conducted a stakeholder process in 2018 for primary frequency response requirements for generators, however was unable to reach stakeholder consensus. One of the concerns raised from our members was that this is an Interconnection product, and as such PJM encourages NERC to continue this discussion in the Standard Drafting Team process.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SAR approved by the Standards Committee under which this drafting team is working states in the second bullet under Phase II "Although Balancing Authorities (BAs) and FRSGs are responsible for coordination and/or management of Frequency Response from both resources and loads, response from resources is not addressed. The review should determine if additional reliability entities should have responsibility (e.g., Generator Operators (GOPs)) for provision of generator governor response; and". Therefore, the SDT will discuss and potentially recommend additional requirements in the future related to other entities. The SDT adds that it is unlikely to recommend removing the existing requirement related to BAs and FRSGs due to the reasoning stated in the SAR. Future postings for comments related to BAL-003 will allow for industry feedback on this issue.

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric

Answer	
Document Name	
Comment	

Any further reduction in frequency response is not acceptable.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The comment does not provide adequate information to respond.	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
AZPS would like to point out that the changes made to the Violation Severity Levels for R1 unintentionally created multiple outcomes based on certain criteria. The way the Moderate, High, and Severe VSLs are described, a Balancing Authority could have a less negative FRM than its FRO reflected in MW/0.1 Hz that qualifies for multiple levels. For example, if a BA had a deficiency between 31-45 MW, it could qualify as both Moderate and High. Deficiencies of 46 MW or greater could qualify as both Moderate and Severe. The use of the word “or” allows for this dilemma. AZPS does not recommend removing the word “or,” but rather completing the ranges with the levels to eliminate this confusion.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT revised the VSL table.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	

Comment	
BPA noticed in review of the revised standard that the Violation Severity Levels are less restrictive. This change was not in the list of modifications at the start of this document. BPA cannot agree with less restrictive VSLs in combination with the current median FRM score utilized for compliance. BPA feels that if an entity does not meet the median it should be at the severe VSL. However, in order to move onto Phase II of the 2017-01 project, BPA suggests the following approach until Phase II can be completed Alternative Approach: BPA suggests that the VSLs for R1 be made more restrictive. Lower Level between 1% and 5%, moderate 5% to 10%, high 10% to 15% and Severe greater than 15%. In WECC, the majority of selected frequency events have loss of less than 1000 MW with a nadir of 59.9 Hz or greater (less than or equal to 100 mHz deviation.) If an entity cannot comply with the median FRM, that entity has high probability of never being able to respond adequately to an event the size of the RLPC. If multiple entities have an FRM less than the median, the interconnection is at a high risk of underfrequency load shed when a loss as great as the RLPC occurs. Therefore, BPA believes the VSLs must be more restrictive than the proposed to support interconnection reliability.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Due to the range in size of BAs and the allocated FRO’s to these different entities, at this time the SDT disagrees with the levels proposed by BPA. As the SDT works on possible revisions to the allocation methodology under Phase II, this issue will be considered.	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	
Document Name	
Comment	

Xcel Energy would like to ensure that the proposed change to the C point to 20 seconds instead of 12 seconds (as specified on Page 1 of the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document is consistently changed throughout the document. For example, it is not clear if the language on page 1 in 3b needs modification ("18 seconds"), and page 2 item 5 ("18 seconds"). Also, we would like to understand how proposed changes to the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* document will gather input from industry and also any approved changes publicized, if not through the standards process (ie standards development distribution lists).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT revised the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* for consistency. The process to change the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard* is something outside the SDT scope. According to the document itself, the NERC BOT must approve changes to the document after posting for public comment. The SDT believes that including the document in the posting of the revised standard addresses this requirement. However, any entity can suggest changes to the document and NERC would then post the changes for comment in any public forum NERC desires.	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
Table 1, which starts on page 12 and ends on page 13 of the proposed standard reflects a value of 120MW as "Credit for Load Resources" for the Western Interconnection. The California ISO suggests that this number be validated as accurate at this point in time.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT has removed the Credit for Load Resources (CLR) in the Western Interconnection.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
SRP supports the proposed revisions and does not have additional comments for the SDT.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the second draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	04/18/2018
SAR posted for comment	03/19/2018 – 03/28/2018
45-day formal or informal comment period with ballot	12/04/2018 – 01/17/2019

Anticipated Actions	Date
10-day final ballot	10/09/2019-10/18/2019
Board adoption	11/06/2019

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

A. Introduction

1. **Title: Frequency Response and Frequency Bias Setting**
2. **Number: BAL-003-2**
3. **Purpose:** To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.
4. **Applicability:**

    4.1. Functional Entities:

    4.1.1. Balancing Authority

    4.1.1.1. Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.

    4.1.2. Frequency Response Sharing Group

5. **Effective Date:** See Implementation Plan for BAL-003-2.

B. Requirements and Measures

R1. Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) 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. *[Risk Factor: High][Time Horizon: Real-time Operations]*

M1. Each Frequency Response Sharing Group or Balancing Authority that is not a member of a Frequency Response Sharing Group shall have evidence such as dated data plus documented formula in either hardcopy or electronic format that it achieved an annual FRM (in accordance with the methods specified by the ERO in Attachment A with data from FRS Form 1 reported to the ERO as specified in Attachment A) that is equal to or more negative than its FRO to demonstrate compliance with Requirement R1.

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 in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. *[Risk Factor: Medium][Time Horizon: Operations Planning]*

M2. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service shall have evidence such as a dated document in hard copy or electronic format showing the ERO validated Frequency Bias Setting was implemented into its ACE calculation within the implementation period specified or other evidence to demonstrate compliance with Requirement R2.

R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

3.1 Less than zero at all times, and

3.2 Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.

M3. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and is utilizing variable Frequency Bias shall have evidence such as a dated report in hard copy or electronic format showing the average clock-minute average Frequency Bias Setting was less than zero and during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was equal to or more negative than its Frequency Response Obligation to demonstrate compliance with Requirement R3.

R4. 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 to either: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

- The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or

- The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.

M4. The Balancing Authority shall have evidence such as a dated operating log, database or list in hard copy or electronic format showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation as specified in Requirement R4 to demonstrate compliance with Requirement R4.

C. Compliance

1. **Compliance Monitoring Process**

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

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

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If a Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.
- The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

  - For Interconnections that are also Balancing Authorities, Tie Line Bias control and flat frequency control are equivalent and either is acceptable.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by at most 15% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 15% but by at most 30% or 30 MW/0.1 Hz, whichever is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 30% but by at most 45% or 45 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 45% or by more than 45 MW/0.1 Hz, whichever is the greater deviation from its FRO.
R2.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting failed to implement the validated Frequency Bias Setting value into its ACE calculation within the implementation period specified but did so within 5 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 5 calendar days but less than or equal to 15 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 15 calendar days but less than or equal to 25 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting did not implement the validated Frequency Bias Setting value into its ACE calculation in more than 25 calendar days from the implementation period specified by the ERO.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 1% but by at most 10%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 10% but by at most 20%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 20% but by at most 30%.	The Balancing Authority that is a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response obligation by more than 30%.
R4.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error less than or equal to 10% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 10% but less than or equal to 20% of the	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 20% but less than or equal to 30% of the	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 30% of the validated or calculated value. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		validated or calculated value.	validated or calculated value.	The Balancing Authority failed to change the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services.

D. Regional Variances

None.

E. Associated Documents

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

FRS Form 1

FRS Form 2

Frequency Response Standard Background Document

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	March 16, 2007	FERC Approval — Order 693	New
0a	December 19, 2007	Added Appendix 1 — Interpretation of R3 approved by BOT on October 23, 2007	Addition
0a	July 21, 2008	FERC Approval of Interpretation of R3	Addition
0b	February 12, 2008	Added Appendix 2 — Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition
0.1b	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial; updated version number to “0.1b”	Errata
0.1b	October 29, 2008	BOT approved errata changes	Errata
0.1a	May 13, 2009	FERC Approved errata changes – version changed to 0.1a (Interpretation of R2, R2.2, R5, and R5.1 not yet approved)	Errata
0.1b	May 21, 2009	FERC Approved Interpretation of R2, R2.2, R5, and R5.1	Addition
1	February 7, 2013	Adopted by NERC Board of Trustees	Complete Revision under Project 2007-12
1	January 16, 2014	FERC Order issued approving BAL-003-1. (Order becomes effective for R2, R3, and R4 April 1, 2015. R1 becomes effective April 1, 2016.)	
1	May 7, 2014	NERC Board of Trustees adopted revisions to VRF and VSLs in Requirement R1.	
1	November 26, 2014	FERC issued a letter order approved VRF and VSL revisions to Requirement R1.	

Version	Date	Action	Change Tracking
1.1	August 25, 2015	Added numbering to Introduction section, corrected parts numbering for R3, and adjusted font within section M4.	Errata
1.1	November 13, 2015	FERC Letter Order approved errata to BAL-003-1.1. Docket RD15-6-000	Errata
2		NERC Board of Trustees adopted BAL-003-2	New

Attachment A

BAL-003-2 Frequency Response and Frequency Bias Setting Standard

Supporting Document

Interconnection Frequency Response Obligation

The ERO, in consultation with regional representatives, has established a target reliability criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). Preliminary values are provided below. Certain values are assessed annually according to the methodology which is detailed in the [Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard].

Interconnection	**Eastern**	**Western**	**ERCOT**	**HQ**	Units
Max. Delta Frequency (MDF)	**0.420**	**0.280**	**0.405**	**0.947**	
Resource Loss Protection Criteria (RLPC)[1]	**3,209**	**2,850**	**2,750**	**2,000**	MW
Credit for Load Resources (CLR)			**1,209**		MW
Current IFRO (OY 2018)	**-1,015**	**-858**	**-381**	**-179**	MW/0.1 Hz
First-Step target IFRO[1]	**-915**	**-1018**	**-380**	**-211**	MW/0.1 Hz
Second-Step target IFRO[1, 2]	**-815**				
Final target IFRO[1, 2]	**-784**				

Table 1: Interconnection Frequency Response Obligations (base year 2017)

IFRO = (RLPC – CLR)/Max Delta Freq/10

1. *These values are evaluated annually for changes in each Interconnection.*
2. *To reduce risk, the Eastern Interconnection IFRO will be stepped down annually from the 2017 value of -1,015 MW/0.1 Hz in -100 MW/0.1 Hz increments. If during the step down process, Interconnection Frequency Response Measure (FRM) declines by more than 10 percent, the ERO will halt the reduction in IFRO until such time that a determination can be made as to the cause of the degradation.*

Balancing Authority Frequency Response Obligation and Frequency Bias Setting

For a multiple Balancing Authority interconnection, the Interconnection FRO shown in Table 1 is allocated based on the Balancing Authority annual load and annual generation. The FRO allocation will be based on the following method:

$$\mathrm{FRO_{BA}} = \mathrm{IFRO} \quad \times \frac{\text{Annual Gen}_{\text{BA}} + \text{Annual Load}_{\text{BA}}}{\text{Annual Gen}_{\text{Int}} + \text{Annual Load}_{\text{Int}}}$$

Where:

- Annual Gen_{BA} is the total annual output of generating plants within the Balancing Authority Area (BAA).
- Annual Load_{BA} is total annual Load within the BAA.
- Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that interconnection.
- Annual Load_{Int} is the sum of all Annual Load_{BA} values reported in that interconnection.

Balancing Authorities that elect to form a FRSG will calculate a FRSG FRO by adding together the individual BA FRO’s.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_{A} and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Submit a joint Form 1 with the “FRSG“ tab completed for the aggregate performance of the participating Balancing Authorities.

Balancing Authorities that merge or transfer load or generation are encouraged to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation to the Interconnection remains the same and so that CPS limits can be adjusted.

Each Balancing Authority reports its previous year’s FRM, Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised Frequency Bias Settings on FRS Form 1. In addition, each Balancing Authority will report its two largest potential resource losses and any applicable N-2 RAS events in the form. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities will be given 30 days from the date the ERO posts the official list of events to submit their FRS Form 1.

Once the ERO reviews the data submitted in FRS Form 1 and FRS Form 2 for all Balancing Authorities, the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year:

- Frequency Bias Setting
- Frequency Response Obligation (FRO)

Once the data listed above is fully posted, the ERO will announce the three-day implementation period for changing the Frequency Bias Setting if it differs from that shown in the timeline below.

A Balancing Authority using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value):

- Any number the Balancing Authority chooses between 100 percent and 125 percent of its Frequency Response Measure as calculated on FRS Form 1
- Interconnection Minimum as determined by the ERO

For purposes of calculating the minimum Frequency Bias Setting, a Balancing Authority participating in a FRSG will need to calculate its stand-alone FRM using FRS Form 1 and FRS Form 2 to determine its minimum Frequency Bias Setting.

A Balancing Authority providing Overlap Regulation will report the historic peak demand and generation of its combined Balancing Authorities' areas on FRS Form 1 as described in Requirement R4.

Frequency Response Measure

The Balancing Authority will calculate its FRM from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event in a Balancing Authority area that is used to calculate its Frequency Response, expressed in MW/0.1Hz" as calculated on FRS Form 2 for each event shown on FRS Form 1. The events in FRS Form 1 are selected by the ERO using the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is the change in its Net Actual Interchange on its tie lines with adjacent Balancing Authorities divided by the change in Interconnection frequency. Some Balancing Authorities may choose to apply corrections to their Net Actual Interchange (NA_I) values to account for factors such as nonconforming loads. FRS Form 1 and 2 shows the types of adjustments that are allowed. Note that with the exception of the Contingent BA column, any adjustments made must be made for all events in an evaluation year.[1]

The ERO will use a standardized sampling interval of approximately 16 seconds before the event, up to the time of the event for the pre-event NA_I, and frequency (A values), and approximately 20 to 52 seconds after the event for the post-event NA_I (B values) in the computation of SEFRD values, dependent on the data scan rate of the Balancing Authority's Energy Management System (EMS).

All events listed on FRS Form 1 need to be included in the annual submission of FRS Forms 1 and 2. The only time a Balancing Authority should exclude an event is if its tie-line data or its Frequency data is corrupt, or its EMS was unavailable. FRS Form 2 has instructions on how to

[1] As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.

correct the BA's data if the given event is internal to the BA or if other authorized adjustments are used.

Assuming data entry is correct, FRS Form 1 will automatically calculate the Balancing Authority's FRM for the past 12 months as the median of the SEFRD values. A Balancing Authority electing to report as an FRSG or a provider of Overlap Regulation Service will provide an FRS Form 1 for the aggregate of its participants.

To allow Balancing Authorities to plan its operations, events with a "Point C" that cause the Interconnection Frequency to be lower than that shown in Table 1 above (for example, an event in the Eastern Interconnection that causes the Interconnection Frequency to go to 59.4 Hz) or higher than an equal change in frequency going above 60 Hz may be included in the list of events for that Interconnection. However, the calculation of the Balancing Authority response to such an event will be adjusted to show a frequency change only to the Target Minimum Frequency shown in Table 1 above (in the previous example this adjustment would cause Frequency to be shown as 59.5 Hz rather than 59.4 HZ) or a high frequency amount of an equal quantity. Should such an event happen, the ERO will provide additional guidance.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual Balancing Authority's Form 1s, with a summary spreadsheet that contains the sum of each participant's individual event performance.

Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities

Described below is the timeline for the exchange of information between the ERO and Balancing Authorities to:

- Facilitate the assignment of Balancing Authority FRO
- Calculate Balancing Authority FRM
- Determine Balancing Authority Frequency Bias Settings

Target Business Date	Activity
March 1	**FRS Form 1 is posted by the ERO* with all selected events for the operating year for BA usage.**
April 1	**BAs and FRSGs complete their frequency response forms for all four quarters, including the BAs' FBS calculations, returning the results to the ERO.**
May 1	**The ERO validates FBS values, computes the sum of all FBS values for each Interconnection.**
May 15	**The BAs not required to file FERC Form 714 receive a request to provide load and generation data as described in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard***** **to support FRO assignments and determining minimum FBS for the upcoming year. Data to be provided by July 15.**
June 1	The BA implements any changes to their FBS.
November 1	The ERO assigns FRO values and Minimum FBS for the upcoming year to the BAs.

* If 4th quarter posting of FRS Form 1s is delayed, the ERO may adjust the other timelines in this table by a similar amount.

** Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the NERC Board of Trustees (Board).

Description of Current Draft

This is the second draft of the proposed standard.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	04/18/2018
SAR posted for comment	03/19/2018 – 03/28/2018
45-day formal or informal comment period with ballot	12/04/2018 – 01/17/2019

Anticipated Actions	Date
~~45-day formal or informal comment period with ballot~~	~~11/26/2018 – 01/09/2019~~
~~45-day formal or informal comment period with additional ballot~~	~~TBD~~
10-day final ballot	~~TBD~~10/09/2019-10/18/2019
Board adoption	~~TBD~~11/06/2019

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

None

A. Introduction

1. **Title: Frequency Response and Frequency Bias Setting**

2. **Number:** **BAL-003-2**

3. **Purpose:** To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authority

   4.1.1.1. Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.

   4.1.2. Frequency Response Sharing Group

5. **Effective Date:** See Implementation Plan for BAL-003-2.

B. Requirements and Measures

R1. Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) 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. *[Risk Factor: High][Time Horizon: Real-time Operations]*

M1. Each Frequency Response Sharing Group or Balancing Authority that is not a member of a Frequency Response Sharing Group shall have evidence such as dated data plus documented formula in either hardcopy or electronic format that it achieved an annual FRM (in accordance with the methods specified by the ERO in Attachment A with data from FRS Form 1 reported to the ERO as specified in Attachment A) that is equal to or more negative than its FRO to demonstrate compliance with Requirement R1.

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 in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. *[Risk Factor: Medium][Time Horizon: Operations Planning]*

M2. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service shall have evidence such as a dated document in hard copy or electronic format showing the ERO validated Frequency Bias Setting was implemented into its ACE calculation within the implementation period specified or other evidence to demonstrate compliance with Requirement R2.

R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

3.1 Less than zero at all times, and

3.2 Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.

M3. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and is utilizing variable Frequency Bias shall have evidence such as a dated report in hard copy or electronic format showing the average clock-minute average Frequency Bias Setting was less than zero and during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was equal to or more negative than its Frequency Response Obligation to demonstrate compliance with Requirement R3.

R4. 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 to either: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

- The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or
- The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.

M4. The Balancing Authority shall have evidence such as a dated operating log, database or list in hard copy or electronic format showing that when it performed Overlap

Regulation Service, it modified its Frequency Bias Setting in its ACE calculation as specified in Requirement R4 to demonstrate compliance with Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

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

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If a Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.
- The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

- For Interconnections that are also Balancing Authorities, Tie Line Bias control and flat frequency control are equivalent and either is acceptable.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO ~~by more than 1% but~~ by at most ~~15~~30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 1530% ~~but by at most 30%~~ or ~~by more than~~ 30 MW/0.1 Hz, whichever is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 30% but by at most 45% or 45 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 45% or by more than 45 MW/0.1 Hz, whichever is the greater deviation from its FRO.
R2.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting failed to implement the validated Frequency Bias Setting value into its ACE calculation within the implementation period specified but did so within 5 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 5 calendar days but less than or equal to 15 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 15 calendar days but less than or equal to 25 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting did not implement the validated Frequency Bias Setting value into its ACE calculation in more than 25 calendar days from the implementation period specified by the ERO.

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R3.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 1% but by at most 10%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 10% but by at most 20%.	The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 20% but by at most 30%.	The Balancing Authority that is a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response obligation by more than 30%.
R4.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error less than or equal to 10% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 10% but less than or equal to 20% of the	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 20% but less than or equal to 30% of the	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 30% of the validated or calculated value. OR

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
		validated or calculated value.	validated or calculated value.	The Balancing Authority failed to change the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services.

D. Regional Variances

None.

E. Associated Documents

~~Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard~~Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

FRS Form 1

FRS Form 2

Frequency Response Standard Background Document

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	March 16, 2007	FERC Approval — Order 693	New
0a	December 19, 2007	Added Appendix 1 — Interpretation of R3 approved by BOT on October 23, 2007	Addition
0a	July 21, 2008	FERC Approval of Interpretation of R3	Addition
0b	February 12, 2008	Added Appendix 2 — Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition
0.1b	January 16, 2008	Section F: added "1."; changed hyphen to "en dash." Changed font style for "Appendix 1" to Arial; updated version number to "0.1b"	Errata
0.1b	October 29, 2008	BOT approved errata changes	Errata
0.1a	May 13, 2009	FERC Approved errata changes – version changed to 0.1a (Interpretation of R2, R2.2, R5, and R5.1 not yet approved)	Errata
0.1b	May 21, 2009	FERC Approved Interpretation of R2, R2.2, R5, and R5.1	Addition
1	February 7, 2013	Adopted by NERC Board of Trustees	Complete Revision under Project 2007-12
1	January 16, 2014	FERC Order issued approving BAL-003-1. (Order becomes effective for R2, R3, and R4 April 1, 2015. R1 becomes effective April 1, 2016.)	
1	May 7, 2014	NERC Board of Trustees adopted revisions to VRF and VSLs in Requirement R1.	
1	November 26, 2014	FERC issued a letter order approved VRF and VSL revisions to Requirement R1.	
1.1	August 25, 2015	Added numbering to Introduction section, corrected parts numbering for R3, and adjusted font within section M4.	Errata

Version	Date	Action	Change Tracking
1.1	November 13, 2015	FERC Letter Order approved errata to BAL-003-1.1. Docket RD15-6-000	Errata
2		NERC Board of Trustees adopted BAL-003-2	New

Attachment A

BAL-003-2 Frequency Response and Frequency Bias Setting Standard

Supporting Document

Interconnection Frequency Response Obligation

The ERO, in consultation with regional representatives, has established a target reliability criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). Preliminary values are provided below. Certain values are assessed annually according to the methodology which is d~~D~~etailed ~~descriptions of the calculations used in Table 1 below are defined~~ in the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.

Interconnection	Eastern	Western	ERCOT	HQ	Units
Max. Delta Frequency (MDF)	**0.~~419~~420**	**0.280**	**0.~~406~~405**	**0.~~946~~947**	
Resource Loss Protection Criteria (RLPC)[1*]	**3,209**	**2,850**	**2,750**	**2,000**	MW
Credit for Load Resources (CLR)		**~~120~~**	**1,209**		MW
Current IFRO (OY 2018)	**-1,015**	**-858**	**-381**	**-179**	MW/0.1 Hz
First-Step target IFRO[1**]	**-915**	**-~~975~~1018**	**-380**	**-211**	MW/0.1 Hz
Second-Step target IFRO[1, 2**]	**-815**				
Final target IFRO[1, 2**]	**-~~766~~784**				

Table 1: Interconnection Frequency Response Obligations (base year 2017)

IFRO = (RLPC – CLR)/Max Delta Freq/10

1. **These values are evaluated annually for changes in each Interconnection.*
~~1.~~
2. ***To reduce risk, the Eastern Interconnection IFRO will be stepped down annually from the 2017 value of -1,015 MW/0.1 Hz in -100 MW/0.1 Hz increments. If during the step down process, Interconnection Frequency Response Measure (FRM) declines by more than 10 percent, the ERO will halt the reduction in IFRO until such time that a determination can be made as to the cause of the degradation.*

Balancing Authority Frequency Response Obligation and Frequency Bias Setting

For a multiple Balancing Authority interconnection, the Interconnection FRO shown in Table 1 is allocated based on the Balancing Authority annual load and annual generation. The FRO allocation will be based on the following method:

$$\mathrm{FRO_{BA}} = \mathrm{IFRO} \quad \times \frac{\mathrm{Annual\ Gen_{BA}} + \mathrm{Annual\ Load_{BA}}}{\mathrm{Annual\ Gen_{Int}} + \mathrm{Annual\ Load_{Int}}}$$

Where:

- Annual Gen_{BA} is the total annual output of generating plants within the Balancing Authority Area (BAA).
- Annual $Load_{BA}$ is total annual Load within the BAA.
- Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that interconnection.
- Annual $Load_{Int}$ is the sum of all Annual $Load_{BA}$ values reported in that interconnection.

Balancing Authorities that elect to form a FRSG will calculate a FRSG FRO by adding together the individual BA FRO's.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Submit a joint Form 1 with the "FRSG" tab completed for the aggregate performance of the participating Balancing Authorities.

Balancing Authorities that merge or transfer load or generation are encouraged to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation to the Interconnection remains the same and so that CPS limits can be adjusted.

Each Balancing Authority reports its previous year's FRM, Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised Frequency Bias Settings on FRS Form 1. In addition, each Balancing Authority will report its two largest potential resource losses and any applicable N-2 RAS events in the form. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities will be given 30 days from the date the ERO posts the official list of events to submit their FRS Form 1.

Once the ERO reviews the data submitted in FRS Form 1 and FRS Form 2 for all Balancing Authorities, the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year:

- Frequency Bias Setting
- Frequency Response Obligation (FRO)

Once the data listed above is fully posted, the ERO will announce the three-day implementation period for changing the Frequency Bias Setting if it differs from that shown in the timeline below.

A Balancing Authority using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value):

- Any number the Balancing Authority chooses between 100 percent and 125 percent of its Frequency Response Measure as calculated on FRS Form 1
- Interconnection Minimum as determined by the ERO

For purposes of calculating the minimum Frequency Bias Setting, a Balancing Authority participating in a FRSG will need to calculate its stand-alone FRM using FRS Form 1 and FRS Form 2 to determine its minimum Frequency Bias Setting.

A Balancing Authority providing Overlap Regulation will report the historic peak demand and generation of its combined Balancing Authorities' areas on FRS Form 1 as described in Requirement R4.

Frequency Response Measure

The Balancing Authority will calculate its FRM from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event in a Balancing Authority area that is used to calculate its Frequency Response, expressed in MW/0.1Hz" as calculated on FRS Form 2 for each event shown on FRS Form 1. The events in FRS Form 1 are selected by the ERO using the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is the change in its Net Actual Interchange on its tie lines with adjacent Balancing Authorities divided by the change in Interconnection frequency. Some Balancing Authorities may choose to apply corrections to their Net Actual Interchange (NA_I) values to account for factors such as nonconforming loads. FRS Form 1 and 2 shows the types of adjustments that are allowed. Note that with the exception of the Contingent BA column, any adjustments made must be made for all events in an evaluation year.[1]

The ERO will use a standardized sampling interval of approximately 16 seconds before the event, up to the time of the event for the pre-event NA_I, and frequency (A values), and approximately 20 to 52 seconds after the event for the post-event NA_I (B values) in the computation of SEFRD values, dependent on the data scan rate of the Balancing Authority's Energy Management System (EMS).

All events listed on FRS Form 1 need to be included in the annual submission of FRS Forms 1 and 2. The only time a Balancing Authority should exclude an event is if its tie-line data or its Frequency data is corrupt, or its EMS was unavailable. FRS Form 2 has instructions on how to

[1] As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.

correct the BA's data if the given event is internal to the BA or if other authorized adjustments are used.

Assuming data entry is correct, FRS Form 1 will automatically calculate the Balancing Authority's FRM for the past 12 months as the median of the SEFRD values. A Balancing Authority electing to report as an FRSG or a provider of Overlap Regulation Service will provide an FRS Form 1 for the aggregate of its participants.

To allow Balancing Authorities to plan its operations, events with a "Point C" that cause the Interconnection Frequency to be lower than that shown in Table 1 above (for example, an event in the Eastern Interconnection that causes the Interconnection Frequency to go to 59.4 Hz) or higher than an equal change in frequency going above 60 Hz may be included in the list of events for that Interconnection. However, the calculation of the Balancing Authority response to such an event will be adjusted to show a frequency change only to the Target Minimum Frequency shown in Table 1 above (in the previous example this adjustment would cause Frequency to be shown as 59.5 Hz rather than 59.4 HZ) or a high frequency amount of an equal quantity. Should such an event happen, the ERO will provide additional guidance.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual Balancing Authority's Form 1s, with a summary spreadsheet that contains the sum of each participant's individual event performance.

Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities

Described below is the timeline for the exchange of information between the ERO and Balancing Authorities to:

- Facilitate the assignment of Balancing Authority FRO
- Calculate Balancing Authority FRM
- Determine Balancing Authority Frequency Bias Settings

Target Business Date	Activity
March 1	FRS Form 1 is posted by the ERO* with all selected events for the operating year for BA usage.
April 1	BAs and FRSGs complete their frequency response forms for all four quarters, including the BAs' FBS calculations, returning the results to the ERO.
May 1	The ERO validates FBS values, computes the sum of all FBS values for each Interconnection.
May 15	The BAs not required to file FERC Form 714 receive a request to provide load and generation data as described in the ***Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard***** to support FRO assignments and determining minimum FBS for the upcoming year. Data to be provided by July 15.
June 1	The BA implements any changes to their FBS.
November 1	The ERO assigns FRO values and Minimum FBS for the upcoming year to the BAs.

* If 4th quarter posting of FRS Form 1s is delayed, the ERO may adjust the other timelines in this table by a similar amount.

** ~~Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard~~Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

A. Introduction

1. **Title: Frequency Response and Frequency Bias Setting**

2. **Number: BAL-003-~~1.1~~2**

3. **Purpose:** To require sufficient Frequency Response from the Balancing Authority (BA) to maintain Interconnection Frequency within predefined bounds by arresting frequency deviations and supporting frequency until the frequency is restored to its scheduled value. To provide consistent methods for measuring Frequency Response and determining the Frequency Bias Setting.

4. **Applicability:**

   4.1. Functional Entities

   4.1.1. Balancing Authority

   4.1.1.1. ~~The~~ Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.

   4.1.2. Frequency Response Sharing Group

5. **Effective Date:** See Implementation Plan for BAL-003-2.

   ~~**5.1.** In those jurisdictions where regulatory approval is required, Requirements R2, R3 and R4 of this standard shall become effective the first calendar day of the first calendar quarter 12 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R2, R3 and R4 of this standard shall become effective the first calendar day of the first calendar quarter 12 months after Board of Trustees adoption.~~

   ~~**5.2.** In those jurisdictions where regulatory approval is required, Requirements R1 of this standard shall become effective the first calendar day of the first calendar quarter 24 months after applicable regulatory approval. In those jurisdictions where no regulatory approval is required, Requirements R1 of this standard shall become effective the first calendar day of the first calendar quarter 24 months after Board of Trustees adoption.~~

B. Requirements

R1. Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) 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. *[Risk Factor: High][Time Horizon: Real-time Operations]*

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 in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. *[Risk Factor: Medium][Time Horizon: Operations Planning]*

R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

3.1 Less than zero at all times, and

3.2 Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 Hz by more than +/- 0.036 Hz.

R4. 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 to either: *[Risk Factor: Medium][Time Horizon: Operations Planning]*

- The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or

- The Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.

Measures

M1. Each Frequency Response Sharing Group or Balancing Authority that is not a member of a Frequency Response Sharing Group shall have evidence such as dated data plus documented formula in either hardcopy or electronic format that it achieved an annual FRM (in accordance with the methods specified by the ERO in Attachment A with data from FRS Form 1 reported to the ERO as specified in Attachment A) that is equal to or more negative than its FRO to demonstrate compliance with Requirement R1.

M2. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service shall have evidence such as a dated document in hard copy or electronic format showing the ERO validated Frequency Bias Setting was implemented into its ACE calculation within the implementation period specified or other evidence to demonstrate compliance with Requirement R2.

M3. The Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and is utilizing variable Frequency Bias shall have evidence such as a dated report in hard copy or electronic format showing the average clock-minute average Frequency Bias Setting was less than zero and during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was equal to or more negative than its Frequency Response Obligation to demonstrate compliance with Requirement R3.

M4. The Balancing Authority shall have evidence such as a dated operating log, database or list in hard copy or electronic format showing that when it performed Overlap Regulation Service, it modified its Frequency Bias Setting in its ACE calculation as specified in Requirement R4 to demonstrate compliance with Requirement R4.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority: "Compliance Enforcement Authority" means NERC or the Regional Entity, or any entity as otherwise designated by an Applicable Governmental Authority, in their respective roles of monitoring and/or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions.

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

The applicable entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

- The Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.
- If a Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.
- The Compliance Enforcement Authority shall keep the last audit records and all subsequent requested and submitted records.

1.3. Compliance Monitoring and Enforcement Program: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

- For Interconnections that are also Balancing Authorities, Tie Line Bias control and flat frequency control are equivalent and either is acceptable.

~~**1. Compliance Monitoring Process**~~

~~**1.1. Compliance Enforcement Authority**~~

~~The Regional Entity is the Compliance Enforcement Authority except where the responsible entity works for the Regional Entity. Where the responsible entity works for the Regional Entity, the Regional Entity will establish an agreement with the ERO or another entity approved by the ERO and FERC (i.e. another Regional Entity), to be responsible for compliance enforcement.~~

~~**1.2 Compliance Monitoring and Assessment Processes:**~~

~~Compliance Audits~~

~~Self-Certifications~~

~~Spot Checking~~

~~Compliance Investigation~~

~~Self-Reporting~~

~~Complaints~~

~~**1.3 Data Retention**~~

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

~~The Balancing Authority shall retain data or evidence to show compliance with Requirements R1, R2, R3 and R4, Measures M1, M2, M3 and M4 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.~~

~~The Frequency Response Sharing Group shall retain data or evidence to show compliance with Requirement R1 and Measure M1 for the current year plus the previous three calendar years unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.~~

~~If a Balancing Authority or Frequency Response Sharing Group is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the time period specified above, whichever is longer.~~

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

~~**1.4 Additional Compliance Information**~~

~~For Interconnections that are also Balancing Authorities, Tie Line Bias control and flat frequency control are equivalent and either is acceptable.~~

2.0 Violation Severity Levels

R#	Lower VSL	~~Medium~~ Moderate VSL	High VSL	Severe VSL
R1	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO ~~by more than 1% but~~ by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than 15% but by at most 30% or ~~by more than 15~~ 30 MW/0.1 Hz, whichever is the greater deviation from its FRO	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than ~~1~~30% but by at most 45% ~~but by at most 30%~~ or ~~15~~ 45 MW/0.1 Hz, whichever one is the greater deviation from its FRO	The Balancing Authority's, or Frequency Response Sharing Group's, FRM was less negative than its FRO by more than ~~30~~45% or by more than ~~15~~ 45 MW/0.1 Hz, whichever is the greater deviation from its FRO
R2	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting failed to implement the validated Frequency Bias Setting value into its ACE calculation within the implementation period specified but did so within 5 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 5 calendar days but less than or equal to 15 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting implemented the validated Frequency Bias Setting value into its ACE calculation in more than 15 calendar days but less than or equal to 25 calendar days from the implementation period specified by the ERO.	The Balancing Authority in a multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting did not implement the validated Frequency Bias Setting value into its ACE calculation in more than 25 calendar days from the implementation period specified by the ERO.
R3	The Balancing Authority that is a member of a	The Balancing Authority that is a member of a	The Balancing Authority that is a member of a	The Balancing Authority that is a multiple Balancing

	multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 1% but by at most 10%.	multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 10% but by at most 20%.	multiple Balancing Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response Obligation by more than 20% but by at most 30%.	Authority Interconnection and not receiving Overlap Regulation Service and uses a variable Frequency Bias Setting average Frequency Bias Setting during periods when the clock-minute average frequency was outside of the range 59.964 Hz to 60.036 Hz was less negative than its Frequency Response obligation by more than 30%.~~.~~
R4	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error less than or equal to 10% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 10% but less than or equal to 20% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 20% but less than or equal to 30% of the validated or calculated value.	The Balancing Authority incorrectly changed the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services with combined footprint setting-error more than 30% of the validated or calculated value. OR The Balancing Authority failed to change the Frequency Bias Setting value used in its ACE calculation when providing Overlap Regulation Services.

D. Regional Variance

None

E. Associated Documents

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

FRS Form 1

FRS Form 2

Frequency Response Standard Background Document

~~Frequency Response Standard Background Document~~

F. Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
0	March 16, 2007	FERC Approval — Order 693	New
0a	December 19, 2007	Added Appendix 1 — Interpretation of R3 approved by BOT on October 23, 2007	Addition
0a	July 21, 2008	FERC Approval of Interpretation of R3	Addition
0b	February 12, 2008	Added Appendix 2 — Interpretation of R2, R2.2, R5, and R5.1 approved by BOT on February 12, 2008	Addition
0.1b	January 16, 2008	Section F: added “1.”; changed hyphen to “en dash.” Changed font style for “Appendix 1” to Arial; updated version number to “0.1b”	Errata
0.1b	October 29, 2008	BOT approved errata changes	Errata
0.1a	May 13, 2009	FERC Approved errata changes – version changed to 0.1a (Interpretation of R2, R2.2, R5, and R5.1 not yet approved)	Errata

0.1b	May 21, 2009	FERC Approved Interpretation of R2, R2.2, R5, and R5.1	Addition
1	February 7, 2013	Adopted by NERC Board of Trustees	Complete Revision under Project 2007-12
1	January 16, 2014	FERC Order issued approving BAL-003-1. (Order becomes effective for R2, R3, and R4 April 1, 2015. R1 becomes effective April 1, 2016.)	
1	May 7, 2014	NERC Board of Trustees adopted revisions to VRF and VSLs in Requirement R1.	
1	November 26, 2014	FERC issued a letter order approved VRF and VSL revisions to Requirement R1.	
1.1	August 25, 2015	Added numbering to Introduction section, corrected parts numbering for R3, and adjusted font within section M4.	Errata
1.1	November 13, 2015	FERC Letter Order approved errata to BAL-003-1.1. Docket RD15-6-000	Errata
2		NERC Board of Trustees adopted BAL-003-2	New

Attachment A

BAL-003-1 Frequency Response ~~&~~ and Frequency Bias Setting Standard

Supporting Document

Interconnection Frequency Response Obligation ~~(IFRO)~~

The ERO, in consultation with regional representatives, has established a target ~~contingency protection~~reliability criterion for each Interconnection called the Interconnection Frequency Response Obligation (IFRO). Preliminary values are provided below. Certain values are assessed annually according to the methodology which is detailed in the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.~~The default IFRO listed in Table 1 is based on the resource contingency criteria (RCC), which is the largest category C (N-2) event identified except for the Eastern Interconnection, which uses the largest event in the last 10 years. A maximum delta frequency (MDF) is calculated by adjusting a starting frequency for each Interconnection by the following:~~

- ~~Prevailing UFLS first step~~
- ~~CC_{Adj} which is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data~~
- ~~CB_R which is the statistically determined ratio of the Point C to Value B~~
- ~~BC'_{Adj} which is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.~~

~~The IFRO for each Interconnection in Table 1 is then calculated by dividing the RCC MWs by 10 times the MDF. In the Eastern Interconnection there is an additional adjustment (BC'_{Adj}) for the event nadir being below the Value B due to primary frequency response withdrawal. This IFRO includes uncertainty adjustments at a 95 % confidence level. Detailed descriptions of the calculations used in Table 1 below are defined in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*.~~

Interconnection	Eastern	Western	ERCOT	HQ	Units
Max. Delta Frequency (MDF)	0.420	0.280	0.405	0.947	
Resource Loss Protection Criteria (RLPC)[1]	3,209	2,850	2,750	2,000	MW
Credit for Load Resources (CLR)			1,209		MW
Current IFRO (OY 2018)	-1,015	-858	-381	-179	MW/0.1 Hz
First-Step target IFRO[1]	-915	-1018	-380	-211	MW/0.1 Hz
Second-Step target IFRO[1, 2]	-815				
Final target IFRO[1, 2]	-784				

Table 1: Interconnection Frequency Response Obligations (base year 2017)

IFRO = (RLPC – CLR)/Max Delta Freq/10

1. *These values are evaluated annually for changes in each Interconnection.*
2. *To reduce risk, the Eastern Interconnection IFRO will be stepped down annually from the 2017 value of -1,015 MW/0.1 Hz in -100 MW/0.1 Hz increments. If during the step down process, Interconnection Frequency Response Measure (FRM) declines by more than 10 percent, the ERO will halt the reduction in IFRO until such time that a determination can be made as to the cause of the degradation.*

~~Interconnection~~	~~Eastern~~	~~Western~~	~~ERCOT~~	~~HQ~~	~~Units~~
~~Starting Frequency (F_{Start})~~	~~59.974~~	~~59.976~~	~~59.963~~	~~59.972~~	~~Hz~~
~~Prevailing UFLS First Step~~	~~59.5*~~	~~59.5~~	~~59.3~~	~~58.5~~	~~Hz~~
~~Base Delta Frequency (DF_{Base})~~	~~0.474~~	~~0.476~~	~~0.663~~	~~1.472~~	~~Hz~~
~~CC_{ADJ}~~	~~0.007~~	~~0.004~~	~~0.012~~	~~N/A~~	~~Hz~~
~~Delta Frequency (DF_{CC})~~	~~0.467~~	~~0.472~~	~~0.651~~	~~1.472~~	~~Hz~~
~~CB_R~~	~~1.000~~	~~1.625~~	~~1.377~~	~~1.550~~	
~~Delta Frequency (DF_{CBR})~~	~~0.467~~	~~0.291~~	~~0.473~~	~~0.949~~	~~Hz~~
~~BC'_{ADJ}~~	~~0.018~~	~~N/A~~	~~N/A~~	~~N/A~~	~~Hz~~
~~Max. Delta Frequency (MDF)~~	~~0.449~~	~~0.291~~	~~0.473~~	~~0.949~~	
~~Resource Contingency Criteria (RCC)~~	~~4,500~~	~~2,740~~	~~2,750~~	~~1,700~~	~~MW~~
~~Credit for Load Resources (CLR)~~		~~300~~	~~1,400**~~		~~MW~~
~~IFRO~~	~~-1,002~~	~~-840~~	~~-286~~	~~-179~~	~~MW/0.1 Hz~~

~~**Table 1: Interconnection Frequency Response Obligations**~~

~~**The Eastern Interconnection UFLS set point listed is a compromise value set midway between the stable frequency minimum established in PRC-006-1 (59.3 Hz) and the local protection UFLS setting of 59.7 Hz used in Florida and Manitoba.*~~

~~***In the Base Obligation measure for ERCOT, 1400 MW (Load Resources triggered by Under Frequency Relays at 59.70 Hz) was reduced from its Resource Contingency Criteria level of 2750 MW to get 239 MW/0.1 Hz. This was reduced to accurately account for designed response from Load Resources within 30 cycles.*~~

~~An Interconnection may propose alternate IFRO protection criteria to the ERO by submitting a SAR with supporting technical documentation.~~

Balancing Authority Frequency Response Obligation ~~(FRO)~~ and Frequency Bias Setting

~~The ERO will manage the administrative procedure for annually assigning an FRO and implementation of the Frequency Bias Setting for each Balancing Authority. The annual timeline for all activities described in this section are shown below.~~

For a multiple Balancing Authority interconnection, the Interconnection FRO ~~Frequency Response Obligation~~ shown in Table 1 is allocated based on the Balancing Authority annual load and annual generation. The FRO allocation will be based on the following method:

$$FRO_{BA} = IFRO \times \frac{\text{Annual Gen}_{BA} + \text{Annual Load}_{BA}}{\text{Annual Gen}_{Int} + \text{Annual Load}_{Int}}$$

Where:

- Annual Gen_{BA} is the total annual ~~"Output~~ output of ~~Generating~~ generating ~~Plants~~plants" within the Balancing Authority Area (BAA).~~, on FERC Form 714, column c of Part II - Schedule 3.~~
- Annual Load_{BA} is total annual Load within the BAA. ~~, on FERC Form 714, column e of Part II - Schedule 3.~~
- Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that interconnection.
- Annual Load_{Int} is the sum of all Annual Load_{BA} values reported in that interconnection.

~~The data used for this calculation is from the most recently filed Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which utilized data from 2011.~~

~~Balancing Authorities that are not FERC jurisdictional should use the Form 714 Instructions to assemble and submit equivalent data to the ERO for use in the FRO Allocation process.~~

Balancing Authorities that elect to form a FRSG will calculate a FRSG FRO by adding together the individual BA FRO's.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- ~~Jointly s~~Submit a joint Form 1 with the "FRSG" tab completed for the aggregate performance of the participating Balancing Authorities~~the individual BAs' Form 1s, with a summary spreadsheet that contains the sum of each participant's individual event performance~~.

Balancing Authorities that merge or ~~that~~ transfer load or generation are encouraged to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation to the Interconnection remains the same and so that CPS limits can be adjusted.

Each Balancing Authority reports its previous year's ~~Frequency Response Measure (~~FRM~~)~~, Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO each year to allow the ERO to validate the revised Frequency Bias Settings on FRS Form 1. In addition, each Balancing Authority will report its two largest potential resource losses and any applicable N-2 RAS events in the form. If the ERO posts the official list of events after the date specified in the timeline below, Balancing Authorities will be given 30 days from the date the ERO posts the official list of events to submit their FRS Form 1.

Once the ERO reviews the data submitted in FRS Form 1 and FRS Form 2 for all Balancing Authorities, the ERO will use FRS Form 1 data to post the following information for each Balancing Authority for the upcoming year:

- Frequency Bias Setting
- Frequency Response Obligation (FRO)

Once the data listed above is fully posted, the ERO will announce the three-day implementation period for changing the Frequency Bias Setting if it differs from that shown in the timeline below.

A Balancing Authority ~~A~~ using a fixed Frequency Bias Setting sets its Frequency Bias Setting to the greater of (in absolute value):

- Any number the ~~BA~~ Balancing Authority chooses between 100~~%~~ percent and 125~~%~~ percent of its Frequency Response Measure as calculated on FRS Form 1
- Interconnection Minimum as determined by the ERO

For purposes of calculating the minimum Frequency Bias Setting, a Balancing Authority participating in a ~~Frequency Response Sharing Group~~FRSG will need to calculate its stand-alone ~~Frequency Response Measure~~FRM using FRS Form 1 and FRS Form 2 to determine its minimum Frequency Bias Setting.

A Balancing Authority providing Overlap Regulation will report the historic peak demand and generation of its combined ~~BAs'~~ Balancing Authorities' areas on FRS Form 1 as described in Requirement R4.

~~There are occasions when changes are needed to Bias Settings outside of the normal schedule. Examples are footprint changes between Balancing Authorities and major changes in load or generation or the formation of new Balancing Authorities. In such cases the changing Balancing Authorities will work with their Regions, NERC and the Resources Subcommittee to confirm appropriate changes to Bias Settings, FRO, CPS limits and Inadvertent Interchange balances.~~

~~If there is no net change to the Interconnection total Bias, the Balancing Authorities involved will agree on a date to implement their respective change in Bias Settings. The Balancing Authorities and ERO will also agree to the allocation of FRO such that the sum remains the same.~~

~~If there is a net change to the Interconnection total Bias, this will cause a change in CPS2 limits and FRO for other Balancing Authorities in the Interconnection. In this case, the ERO will notify the impacted Balancing Authorities of their respective changes and provide an implementation window for making the Bias Setting changes.~~

Frequency Response Measure ~~(FRM)~~

The Balancing Authority will calculate its FRM from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event ~~from~~ in a Balancing Authority area that is used to calculate its Frequency Response, expressed in MW/0.1Hz" as calculated on FRS Form 2 for each event shown on FRS Form 1. The events in FRS Form 1 are selected by the ERO using the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*. The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is ~~basically~~ the change in its Net Actual Interchange on its tie lines with ~~its~~ adjacent Balancing Authorities divided by the change in Interconnection frequency. ~~(~~Some Balancing Authorities may choose to apply corrections to their Net Actual Interchange (NA_I) values to account for factors such as nonconforming loads. FRS Form 1 and 2 shows the types of adjustments that are allowed. Note that with the exception of the Contingent BA column, any adjustments made must be made for all events in an evaluation year. [1] ~~As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-~~

[1] As an example, if an entity has non-conforming loads and makes an adjustment for one event, all events must show the non-conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.

~~conforming load, even if the non-conforming load does not impact the calculation. This ensures that the reports are not utilizing the adjustments only when they are favorable to the BA.)~~

The ERO will use a standardized sampling interval of approximately 16 seconds before the event, up to the time of the event for the pre-event NA_I, and frequency (A values), and approximately 20 to 52 seconds after the event for the post-event NA_I (B values) in the computation of SEFRD values, dependent on the data scan rate of the Balancing Authority's Energy Management System (EMS).

All events listed on FRS Form 1 need to be included in the annual submission of FRS Forms 1 and 2. The only time a Balancing Authority should exclude an event is if its tie-line data or its Frequency data is corrupt, or its EMS was unavailable. FRS Form 2 has instructions on how to correct the BA's data if the given event is internal to the BA or if other authorized adjustments are used.

Assuming data entry is correct, FRS Form 1 will automatically calculate the Balancing Authority's FRM for the past 12 months as the median of the SEFRD values. A Balancing Authority electing to report as an FRSG or a provider of Overlap Regulation Service will provide an FRS Form 1 for the aggregate of its participants.

To allow Balancing ~~authorities~~ Authorities to plan its operations, events with a "Point C" that cause the Interconnection Frequency to be lower than that shown in Table 1 above (for example, an event in the Eastern Interconnection that causes the Interconnection Frequency to go to 59.4 Hz) or higher than an equal change in frequency going above 60 Hz may be included in the list of events for that ~~interconnection~~Interconnection. However, the calculation of the ~~BA~~ Balancing Authority response to such an event will be adjusted to show a frequency change only to the Target Minimum Frequency shown in Table 1 above (in the previous example this adjustment would cause Frequency to be shown as 59.5 Hz rather than 59.4 HZ) or a high frequency amount of an equal quantity. Should such an event happen, the ERO will provide additional guidance.

Balancing Authorities that elect to form a FRSG as a means to jointly meet the FRO will calculate their FRM performance one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual Balancing Authority's Form 1s, with a summary spreadsheet that contains the sum of each participant's individual event performance.

Timeline for Balancing Authority Frequency Response and Frequency Bias Setting Activities

Described below is the timeline for the exchange of information between the ERO and Balancing Authorities ~~(BA)~~ to:

- Facilitate the assignment of ~~BA~~ Balancing Authority ~~Frequency Response Obligations (~~FRO~~)~~
- Calculate ~~BA~~ Balancing Authority ~~Frequency Response Measures (~~FRM~~)~~
- Determine ~~BA~~ Balancing Authority Frequency Bias Settings ~~(FBS)~~

Target Business Date	Activity
March 1	FRS Form 1 is posted by the ERO* with all selected events for the operating year for BA usage.

April 1	BAs and FRSGs complete their frequency response forms for all four quarters, including the BAs' FBS calculations, returning the results to the ERO.
May 1	The ERO validates FBS values, computes the sum of all FBS values for each Interconnection.
May 15	The BAs not required to file FERC Form 714 receive a request to provide load and generation data as described in the Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard** to support FRO assignments and determining minimum FBS for the upcoming year. Data to be provided by July 15.
June 1	The BA implements any changes to their FBS.
November 1	The ERO assigns FRO values and Minimum FBS for the upcoming year to the BAs.

* If 4th quarter posting of FRS Form 1 is delayed, the ERO may adjust the other timelines in this table by a similar amount.

** Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

~~Target Date~~	~~Activity~~
~~April 30~~	~~The ERO reviews candidate frequency events and selects frequency events for the first quarter (December to February).~~
~~May 10~~	~~Form1 is posted with selected events from the first quarter for BA usage by the ERO.~~
~~May 15~~	~~The BAs receive a request to provide load and generation data as described in Attachment A to support FRO assignments and determining minimum FBS for BAs.~~
~~July 15~~	~~The BAs provide load and generation data as described in Attachment A to the ERO.~~
~~July 30~~	~~The ERO reviews candidate frequency events and selects frequency events for the second quarter (March to May).~~
~~August 10~~	~~Form1 is posted with selected events from the first and second quarters for BA usage by the ERO.~~
~~October 30~~	~~The ERO reviews candidate frequency events and selects frequency events for the third quarter (June to August)~~
~~November 10~~	~~Form1 is posted with selected events from the first, second, and third quarters for BA usage by the ERO.~~
~~November 20~~	~~If necessary, the ERO provides any updates to the necessary Frequency Response.~~
~~November 20~~	~~The ERO provides the fractional responsibility of each BA for the Interconnection's FRO and Minimum FBS to the BAs.~~

~~January 30~~	~~The ERO reviews candidate frequency events and selects frequency events for the fourth quarter (September to November).~~
~~2nd business day in February~~	~~Form1 is posted with all selected events for the year for BA usage by the ERO.~~
~~February 10~~	~~The ERO assigns FRO values to the BAs for the upcoming year.~~
~~March 7~~	~~BAs complete their frequency response sampling for all four quarters and their FBS calculation, returning the results to the ERO.~~
~~March 24~~	~~The ERO validates FBS values, computes the sum of all FBS values for each Interconnection, and determines L10 values for the CPS 2 criterion for each BA as applicable.~~
~~Any time during first 3 business days of April (unless specified otherwise by the ERO)~~	~~The BA implements any changes to their FBS and L10 value.~~

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2017-01 Modifications to BAL-003-1.1
Reliability Standard BAL-003-2

Applicable Standard

- Standard BAL-003-2 — Frequency Response and Frequency Bias Setting

Requested Retirement(s)

- Standard BAL-003-1.1 — Frequency Response and Frequency Bias Setting

Applicable Entities

- Balancing Authority
    - Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.
- Frequency Response Sharing Group

Background

The BAL-003-2 Phase I portion of the project revises the BAL-003-1.1 standard and process documents to address: (1) the inconsistencies in calculation of IFROs due to interconnection Frequency Response performance changes of Point C and/or Value B; (2) the Eastern Interconnection Resource Contingency Protection Criteria; (3) the frequency of nadir point limitations (currently limited to t0 to t+12); (4) clarification of language in Attachment A, i.e. related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities; and (5) enhancements to the BAL-003-1 FRS Forms that include the ability to collect and submit FRSG performance data. Additionally, the supporting procedural and process steps have been removed from Attachment A and captured in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.* This proposed document would be subject to approval by the North American Electric Reliability Corporation Operating Committee and Board of Trustees, and subject to informational filing with the Federal Energy Regulatory Commission, to facilitate timely process improvements as future lessons are learned.

Effective Date

BAL-003-2 — Frequency Response and Frequency Bias Setting
Where approval by an applicable governmental authority is required, the standard shall become effective on the first operating year (which begins on December 1st) that is 90 days after the

effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first operating year (which begins on December 1st) that is 90 days after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

BAL-003-1.1 — Frequency Response and Frequency Bias Setting
Reliability Standard BAL-003-1.1 shall be retired immediately prior to the effective date of BAL-003-2 in the particular jurisdiction in which the revised standard is becoming effective.

Implementation Plan

Project 2017-01 Modifications to BAL-003-1.1
Reliability Standard BAL-003-2

Applicable Standard(s)

- Standard BAL-003-2 — Frequency Response and Frequency Bias Setting

Requested Retirement(s)

- Standard BAL-003-1.1 — Frequency Response and Frequency Bias Setting

Applicable Entities

- Balancing Authority
    - o Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.
- Frequency Response Sharing Group

Background

The BAL-003-2 Phase I portion of the project revises the BAL-003-1.1 standard and process documents to address: (1) the inconsistencies in calculation of IFROs due to interconnection Frequency Response performance changes of Point C and/or Value B; (2) the Eastern Interconnection Resource Contingency Protection Criteria; (3) the frequency of nadir point limitations (currently limited to t0 to t+12); (4) clarification of language in Attachment A, i.e. related to Frequency Response Reserve Sharing Groups (FRSG) and the timeline for Frequency Response and Frequency Bias Setting activities; and (5) enhancements to the BAL-003-1 FRS Forms that include the ability to collect and submit FRSG performance data. Additionally, the supporting procedural and process steps have been removed from Attachment A and captured in the *Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard.* This proposed document would be subject to approval by the North American Electric Reliability Corporation Operating Committee and Board of Trustees, and subject to informational filing with the Federal Energy Regulatory Commission, to facilitate timely process improvements as future lessons are learned.

Effective Date

BAL-003-2 — Frequency Response and Frequency Bias Setting
Where approval by an applicable governmental authority is required, the standard shall become effective on the first operating year (which begins on December 1st) that is 90 days after the

effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard shall become effective on the first operating year (which begins on December 1st) that is 90 days after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

BAL-003-1.1 — Frequency Response and Frequency Bias Setting
Reliability Standard BAL-003-1.1 shall be retired immediately prior to the effective date of BAL-003-2 in the particular jurisdiction in which the revised standard is becoming effective.

Violation Risk Factor and Violation Severity Level Justifications

Project 2017-01 Modifications to BAL-003-1.1

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard BAL-003-2. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements. Please note, the SDT is only proposing to change the VSL for Requirement R1. As a result, justification is only provided for the VSL for Requirement R1.

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the BES, or the ability to effectively monitor and control the BES. However, violation of a medium risk requirement is unlikely to lead to BES instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control, or restore the BES. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to BES instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

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

FERC Guidelines for Violation Risk Factors

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

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

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

Guideline (2) – Consistency within a Reliability Standard

FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards

FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level

Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation

Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

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

VSLs should be based on NERC's overarching criteria shown in the table below:

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

FERC Order of Violation Severity Levels

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

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

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

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

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

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

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

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

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

VRF Justification for BAL-003-1.1, Requirement R1

The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R1

This justification is provided on the following page.

VRF Justification for BAL-003-1.1, Requirement R2

The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R2

The VSL did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VRF Justification for BAL-003-1.1, Requirement R3

The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R3

The VSL did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VRF Justification for BAL-003-1.1, Requirement R4

The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R4

The VSL did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSLs for BAL-003-2, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority's (BA)s, or Frequency Response Sharing Group's (FRSG)s, Frequency Response Measure (FRM) was less negative than its Frequency Response Obligation (FRO) by at most 30% or 15 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The BA's, or (FRSG)s, FRM was less negative than its FRO by more than 30% or 30 MW/0.1 Hz, whichever is the greater deviation from its FRO.	The BA's, or FRSGs, FRM was less negative than its FRO by more than 30% but by at most 45% or 45 MW/0.1 Hz, whichever one is the greater deviation from its FRO.	The BA's, or FRSG's, FRM was less negative than its FRO by more than 45% or by more than 45 MW/0.1 Hz, whichever is the greater deviation from its FRO.

VSL Justifications for BAL-003-2, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is not applicable since there was not a requirement mandating a certain level of Frequency Response prior to this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Proposed VSL's are not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the amount the calculated FRM is less negative than FRO.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Proposed VSL's do not expand on what is required. The VSL's assigned only consider results of the calculation required. Proposed VSL's are consistent with the requirement.

VSL Justifications for BAL-003-2, Requirement R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

Violation Risk Factor and Violation Severity Level Justifications

Project 2017-01 Modifications to BAL-003-1.1

This document provides the standard drafting team's (SDT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Reliability Standard BAL-003-2. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements. Please note, the SDT is only proposing to change the VSL for Requirement R1. As a result, justification is only provided for the VSL for Requirement R1.

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VSL Justification for BAL-003-1.1, Requirement R1

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VRF Justification for BAL-003-1.1, Requirement R2

The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R2

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VRF Justification for BAL-003-1.1, Requirement R3

The VRF did not change from the previously FERC approved BAL-003-1.1 Reliability Standard.

VSL Justification for BAL-003-1.1, Requirement R3

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VSL Justifications for BAL-003-2, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is not applicable since there was not a requirement mandating a certain level of Frequency Response prior to this standard.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Proposed VSL's are not binary. Proposed VSL language does not include ambiguous terms and ensures uniformity and consistency in the determination of penalties based only on the amount the calculated FRM is less negative than FRO.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	Proposed VSL's do not expand on what is required. The VSL's assigned only consider results of the calculation required. Proposed VSL's are consistent with the requirement.

VSL Justifications for BAL-003-2, Requirement R1	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Proposed VSL's are based on a single violation and not a cumulative violation methodology.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Frequency Response Standard Background Document

November, 2012

RELIABILITY | ACCOUNTABILITY

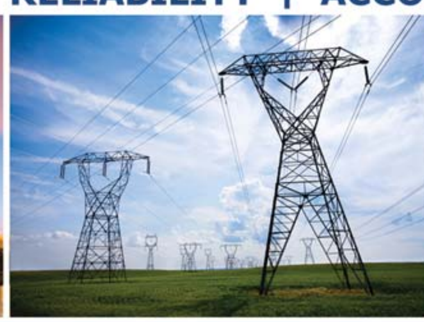

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Table of Contents

Introduction

This document provides background on the development, testing and implementation of BAL-003-1 - Frequency Response Standard ("FRS").[1] The intent is to explain the rationale and considerations for the Requirements of this standard and their associated compliance information. The document also provides good practices and tips for Balancing Authorities ("BAs") with regard to Frequency Response.

In Order No. 693, the Federal Energy Regulatory Commission ("FERC" or the "Commission") directed additional changes to BAL-003.[2] This document explains how compliance with those directives are met by BAL-003-1.

The original Standards Authorization Request ("SAR"), finalized on June 30, 2007, assumed there was adequate Frequency Response in all the North American Interconnections. The goal of the SAR was to update the Standard to make the measurement process of frequency response more objective and to provide this objective data to Planners and Operators for improved modeling. The updated models will improve understanding of the trends in Frequency Response to determine if reliability limits are being approached. The Standard would also lay the process groundwork for a transition to a performance-based Standard if reliability limits are approached.

This document will be periodically updated by the FRS Drafting Team ("FRSDT") until the Standard is approved. Once approved, this document will then be maintained and updated by the ERO and the NERC Resources Subcommittee to be used as a reference and training resource.

Background

This section discusses the different components of frequency control and the individual components of Primary Frequency Control also known as Frequency Response.

Frequency Control

Most system operators generally have a good understanding of frequency control and Bias Setting as outlined in the balancing standards and the references to them in the NERC Operating Manual. Frequency control can be divided into four overlapping windows of time as outlined below.

Primary Frequency Control (Frequency Response) – Actions provided by the Interconnection to arrest and stabilize frequency in response to frequency deviations.

[1] Unless otherwise designated herein, all capitalized terms shall have the meaning set forth in the Glossary of Terms Used in NERC Reliability Standards, available here: http://www.nerc.com/files/Glossary_of_Terms.pdf.

[2] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242 at PP 368-375, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

Primary Control comes from automatic generator governor response (also known as speed regulation), load response (typically from motors), and other devices that provide an immediate response based on local (device-level) control systems.

Secondary Frequency Control – Actions provided by an individual BA or its Reserve Sharing Group to correct the resource – load unbalance that created the original frequency deviation, which will restore both Scheduled Frequency and Primary Frequency Response. Secondary Control comes from either manual or automated dispatch from a centralized control system.

Tertiary Frequency Control – Actions provided by Balancing Authorities on a balanced basis that are coordinated so there is a net zero effect on Area Control Error (ACE). Examples of Tertiary Control include dispatching generation to serve native load; economic dispatch; dispatching generation to affect Interchange; and re-dispatching generation. Tertiary Control actions are intended to replace Secondary Control Response by reconfiguring reserves.

Time Control includes small offsets to scheduled frequency to keep long term average frequency at 60 Hz.

Primary Frequency Control – Frequency Response

Primary Frequency Control, also known generally as **Frequency Response**, is the first stage of overall frequency control and is the response of resources and load to a locally sensed change in frequency in order to arrest that change in frequency. Frequency Response is automatic, not driven by any centralized system, and begins within seconds rather than minutes. Different resources, loads, and systems provide Frequency Response with different response times, based on current system conditions such as total resource/load and their respective mix.

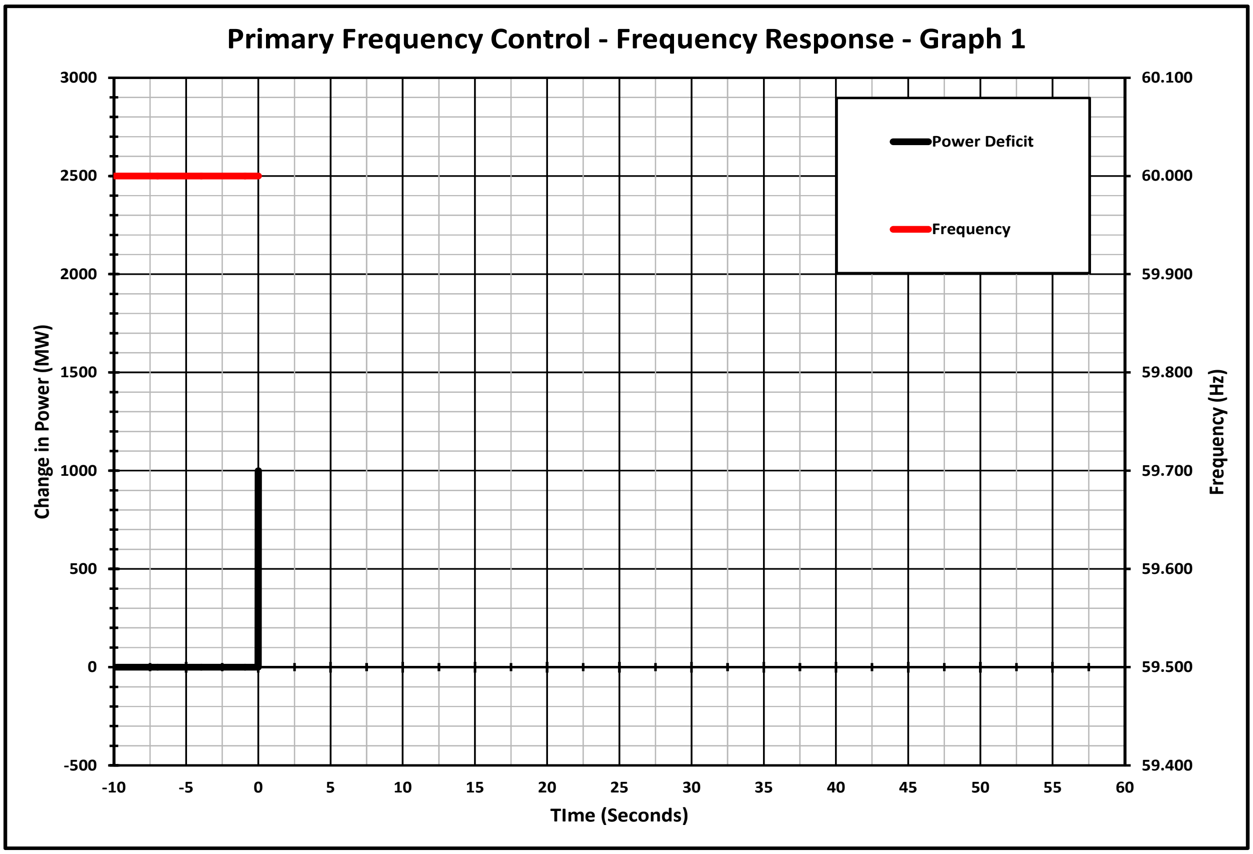
The proposed NERC Glossary of Terms defines **Frequency Response** as:

- (Equipment) The immediate and automatic reaction or response of power from a system or power from elements of the system to a change in locally sensed system frequency.
- (System) The sum of the change in demand, and the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).

As noted above, Frequency Response is the characteristic of load and generation within Balancing Authorities and Interconnections. It reacts or responds with changes in power to attempted changes in load-resource balance that result in changes to system frequency. Because the loss of a large generator is much more likely than a sudden loss of an equivalent amount of load, Frequency Response is typically discussed in the context of a loss of a large generator. Included within Frequency Response are many components of that response. Understanding Frequency Response and the FRS requires an understanding of each of these components and how they relate to each other.

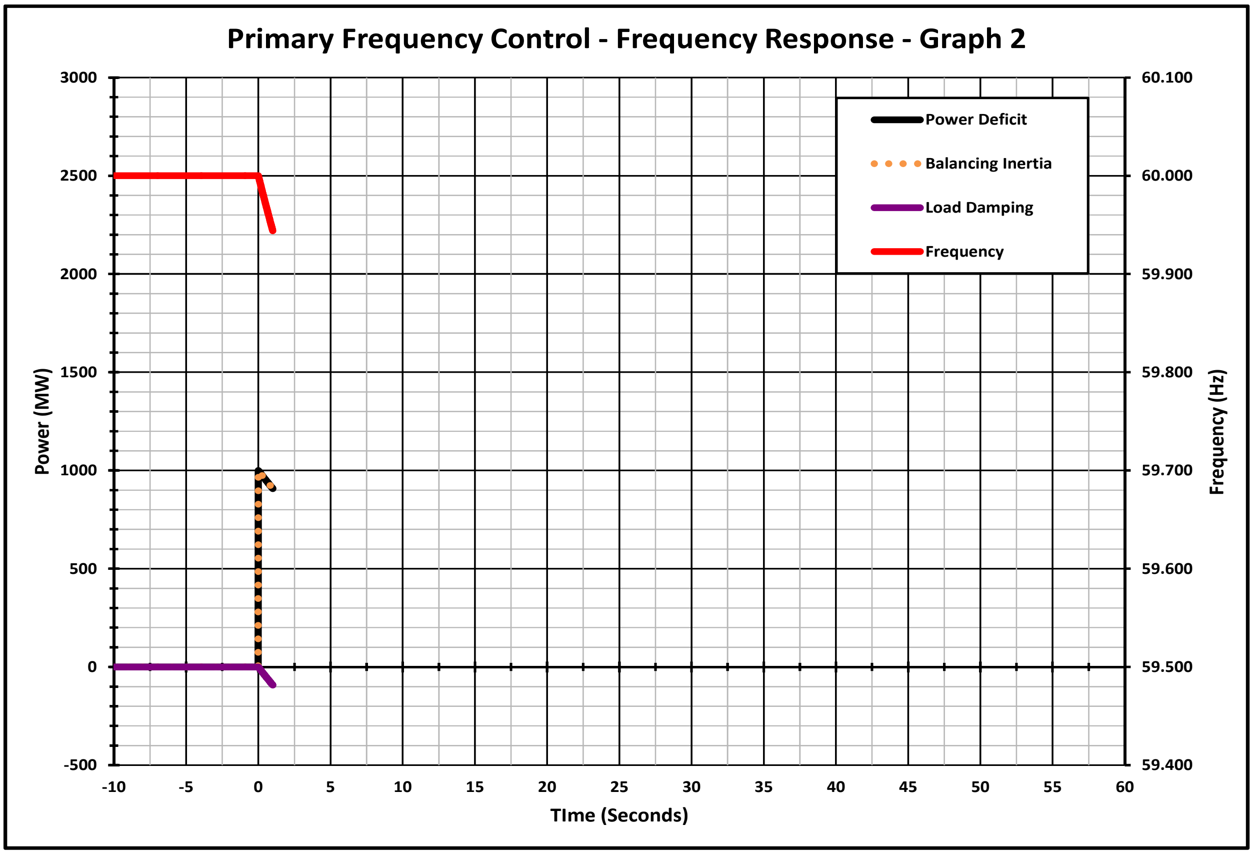
Frequency Response Illustration

The following simple example is presented to illustrate the components of Frequency Response in graphical form. It includes a series of seven graphs that illustrate the various components of Frequency Response and a brief discussion of each describing how these components react to attempted changes in the load-resource balance and resulting changes in system frequency. The illustration is based on an assumed Disturbance event of the sudden loss of 1000 MW of generation. Although a large event is used to illustrate the response components, even small frequently occurring events will result in similar reactions or responses. The magnitude of the event only affects the shape of the curves on the graph; it does not obviate the need for Frequency Response.



The first graph, Primary Frequency Control – Frequency Response – Graph 1, presents a sudden loss of generation of 1000 MW. The components are presented relative to time as shown on the horizontal Time axis in seconds. This simplified example assumes a Disturbance event of the sudden loss of generation resulting from a breaker trip that instantaneously removes 1000 MW of generation from the interconnection. This sudden loss is illustrated by the power deficit line shown in black using the MW scale on the left. Interconnection frequency is illustrated by the frequency line shown in red using the Hertz scale on the right. Since the Scheduled Frequency is normally 60 Hz, it is assumed that this is the frequency when the Disturbance event occurs.

Even though the generation has tripped and power injected by the generator has been removed from the interconnection, the loads continue to use the same amount of power. The "Law of Conservation of Energy"[3] requires that the 1000 MW must be supplied to the interconnection if energy balance is to be "conserved." This additional 1000 MW of power is produced by extracting kinetic energy that was stored in the rotating mass of all of the synchronized generators and motors on the interconnection – essentially using this equipment as a giant flywheel. The extracted energy supplies the "balancing inertia"[4] power required to maintain the power and energy balance on the interconnection. This balancing inertia power is produced by the generators' spinning inertial mass' resistance to the slowdown in speed of the rotating equipment on the interconnection that both provides the stored kinetic energy and reduces the frequency of the interconnection. This is illustrated in the second graph, Primary Frequency Control – Frequency Response – Graph 2, by the orange dots representing the balancing inertia power that exactly overlay and offset the power deficit.



As the frequency decreases, synchronized motors slow, as does the work they are providing, resulting in a decrease in load called "load damping." This load damping is the reason that the power deficit initially declines. Synchronously operated motors will contribute to load

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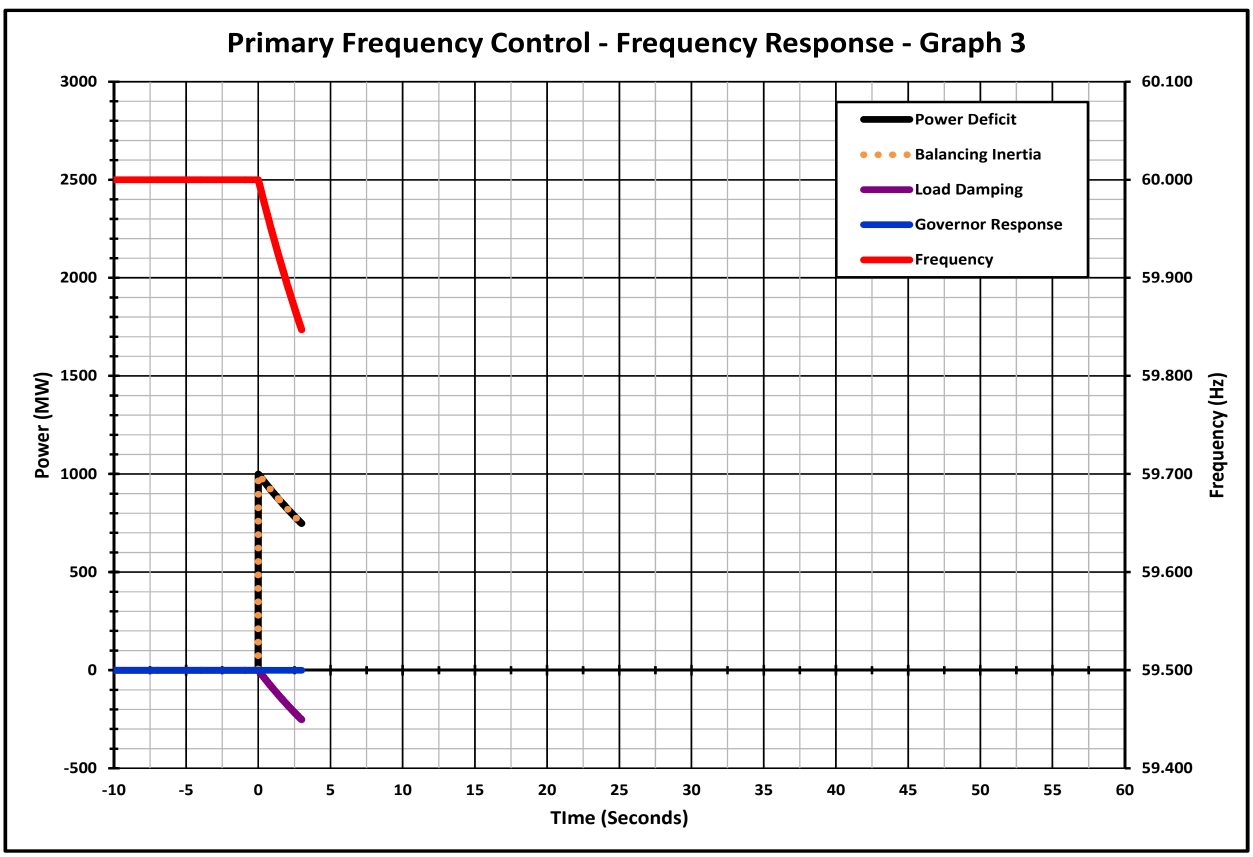
[3] The "Law of Conservation of Energy" is applied here in the form of power. If energy must be conserved, then power which is the first derivative of energy with respect to time, must also be conserved.

[4] The term "balancing Inertia" is coined here from the terms "inertial frequency response" and "balancing energy". Inertial frequency response is a common term used to describe the power supplied for this portion of the frequency response and balancing energy is a term used to describe the market energy supposedly purchased to restore energy balance.

damping. Variable speed drives that are decoupled from the interconnection frequency do not contribute to load damping. In general, any load that does not change with interconnection frequency including resistive load will not contribute to load damping or Frequency Response.

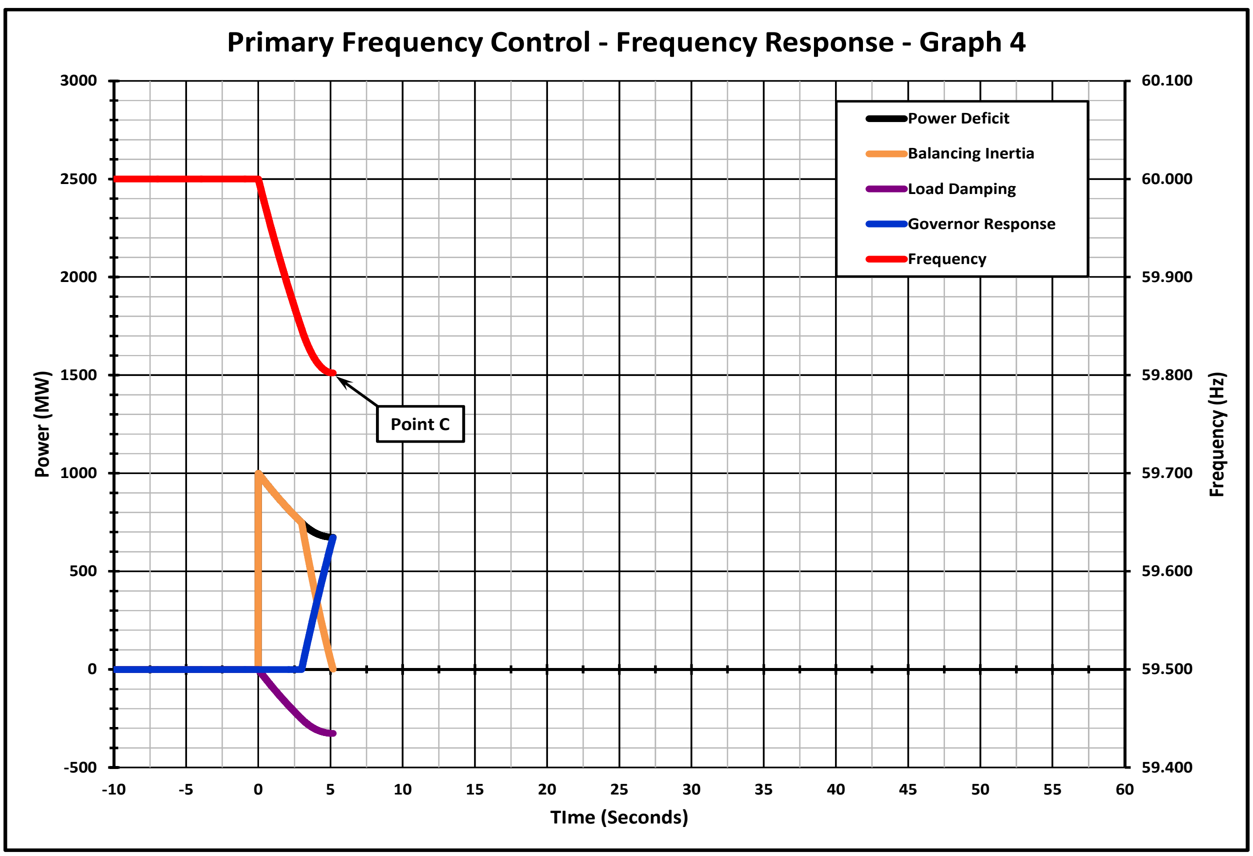
It is important to note that the power deficit equals exactly the balancing inertia, indicating that there is no power or energy imbalance at any time during this process. What is normally considered as "balancing power or energy" is actually power or energy required to correct the frequency error from scheduled frequency. Any apparent power or energy imbalance is corrected instantaneously by the balancing inertia power and energy extracted from the interconnection. Thus the balancing function is really a frequency control function described as a balancing function because ACE is calculated in MWs instead of Hertz, frequency error.

During the initial seconds of the Disturbance event, the governors have yet to respond to the frequency decline. This is illustrated with the Blue line on the third graph, Primary Frequency Control – Frequency Response – Graph 3, showing Governor Response. This time delay results from the time that it takes the controller to adjust the equipment and the time it takes the mass to flow from the source of the energy (main steam control valve for steam turbines, the combustor for gas turbines, or the gate valve for hydro turbines) to the turbine-generator blades where the power is converted to electrical energy.



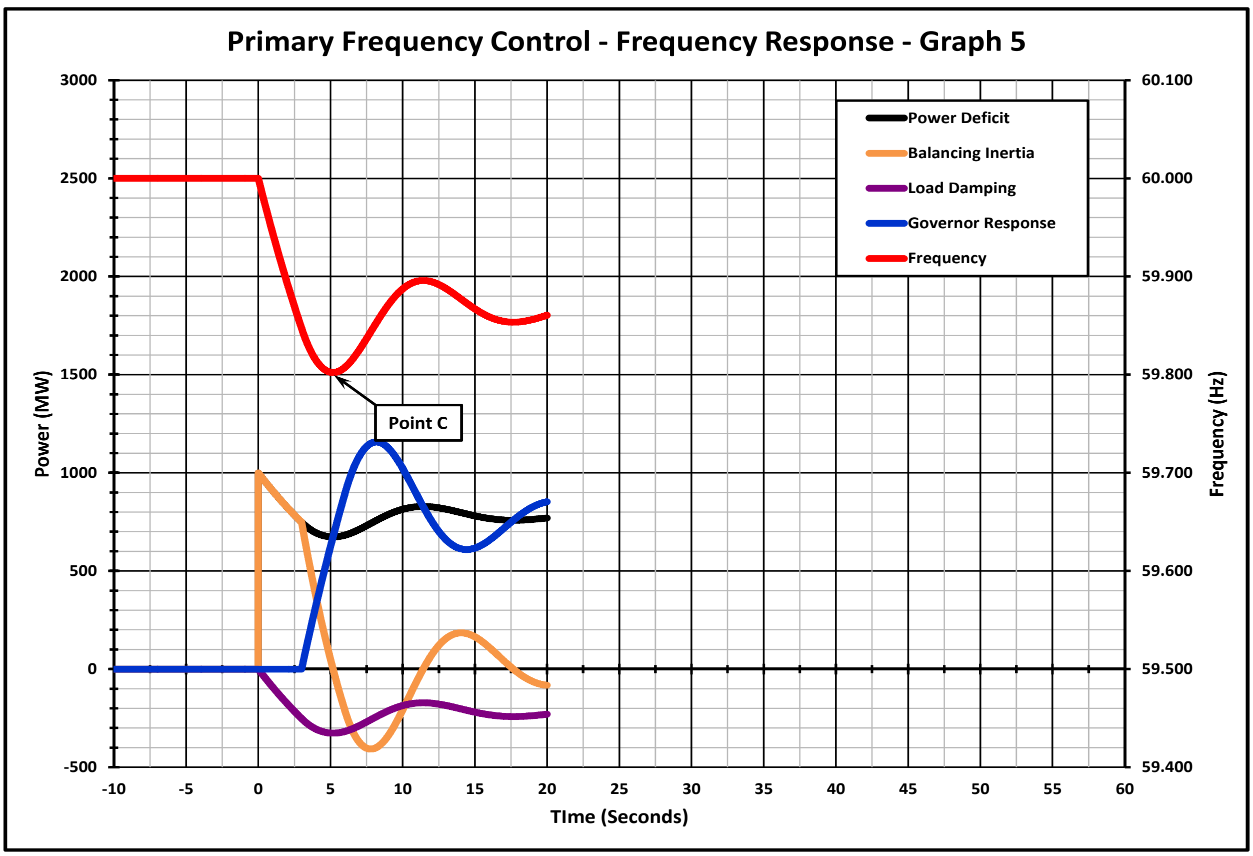
Note that the frequency continues to decline due to the ongoing extraction by balancing inertia power of energy from the rotating turbine-generators and synchronous motors on the interconnection. The reduction in load also continues as the effect of load damping continues to reduce the load while frequency declines. During this time delay (before the governor response begins) the balancing inertia limits the rate of change of frequency.

After a short time delay, the governor response begins to increase rapidly in response to the initial rapid decline in frequency, as illustrated on the fourth graph, Primary Frequency Control – Frequency Response – Graph 4. Governor response exactly offsets the power deficit at the point in time that the frequency decline is arrested. At this point in time, the balancing inertia has provided its contribution to reliability and its power contribution is reduced to zero as it is replaced by the governor response. If the time delay associated with the delivery of governor response is reduced, the amount of balancing inertia required to limit the change in frequency by the Disturbance event can also be reduced. This supports the conclusion that balancing inertia is required to manage the time delays associated with the delivery of Frequency Response. Not only is the rapid delivery of Frequency Response important, but the shortening of the time delay associated with its delivery is also important. Therefore, two important components of Frequency Response are 1) how long the time delay is before the initial delivery of response begins; and 2) how much of the response is delivered before the frequency change is arrested.

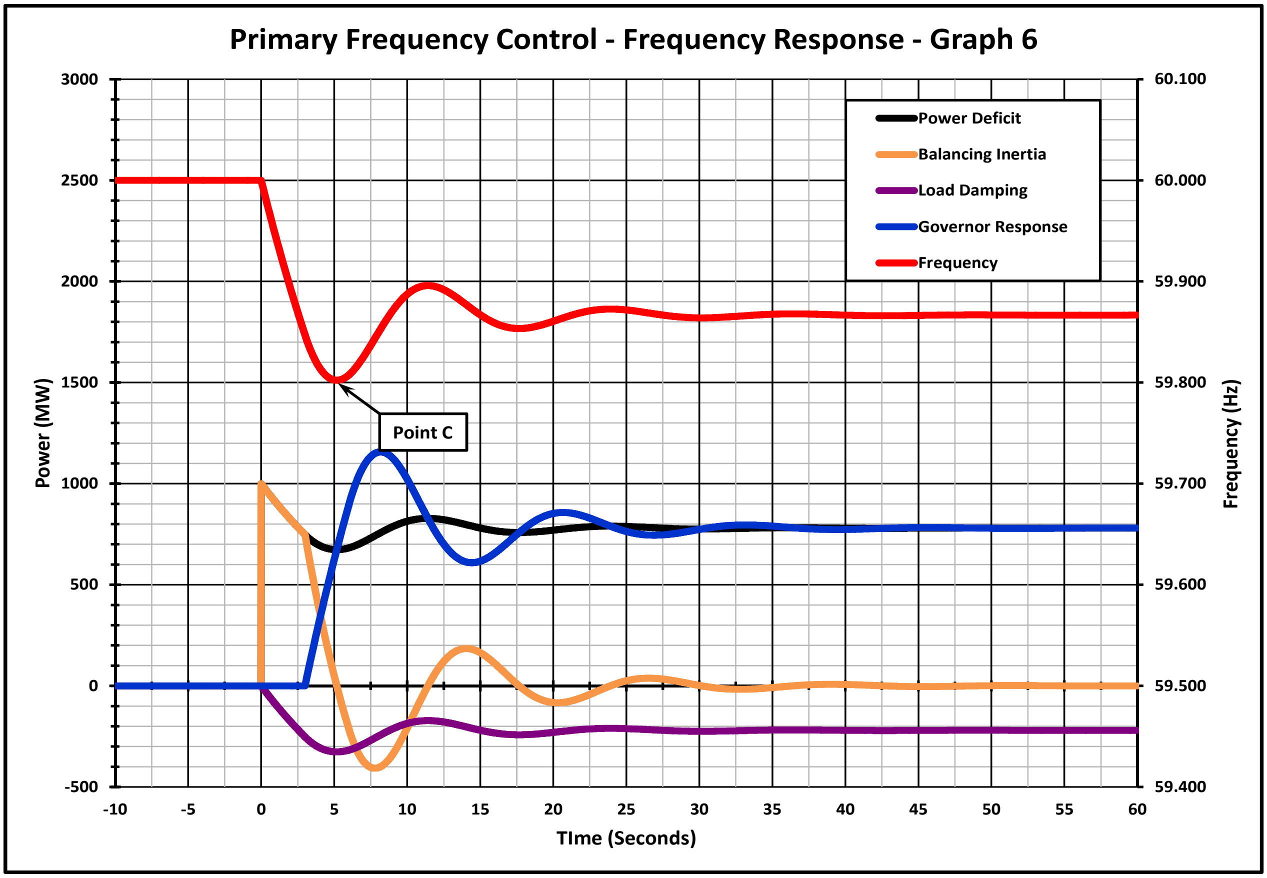


This point, at which the frequency is first arrested, is defined as “Point C” and Frequency Response calculated at this point is called the “**arrested frequency response**.” The arrested frequency is normally the minimum (maximum for load loss events) frequency that will be experienced during a Disturbance event. From a reliability perspective, this minimum frequency is the frequency that is of concern. Adequate reliability requires that frequency at the time frequency is arrested remain above the under-frequency relay settings so as not to trip these relays and the firm load interrupted by them. Frequency Response delivered after frequency is arrested at this minimum level provides less reliability value than Frequency Response delivered before Point C, but greater value than Secondary Frequency Control power and energy which is delivered minutes later.

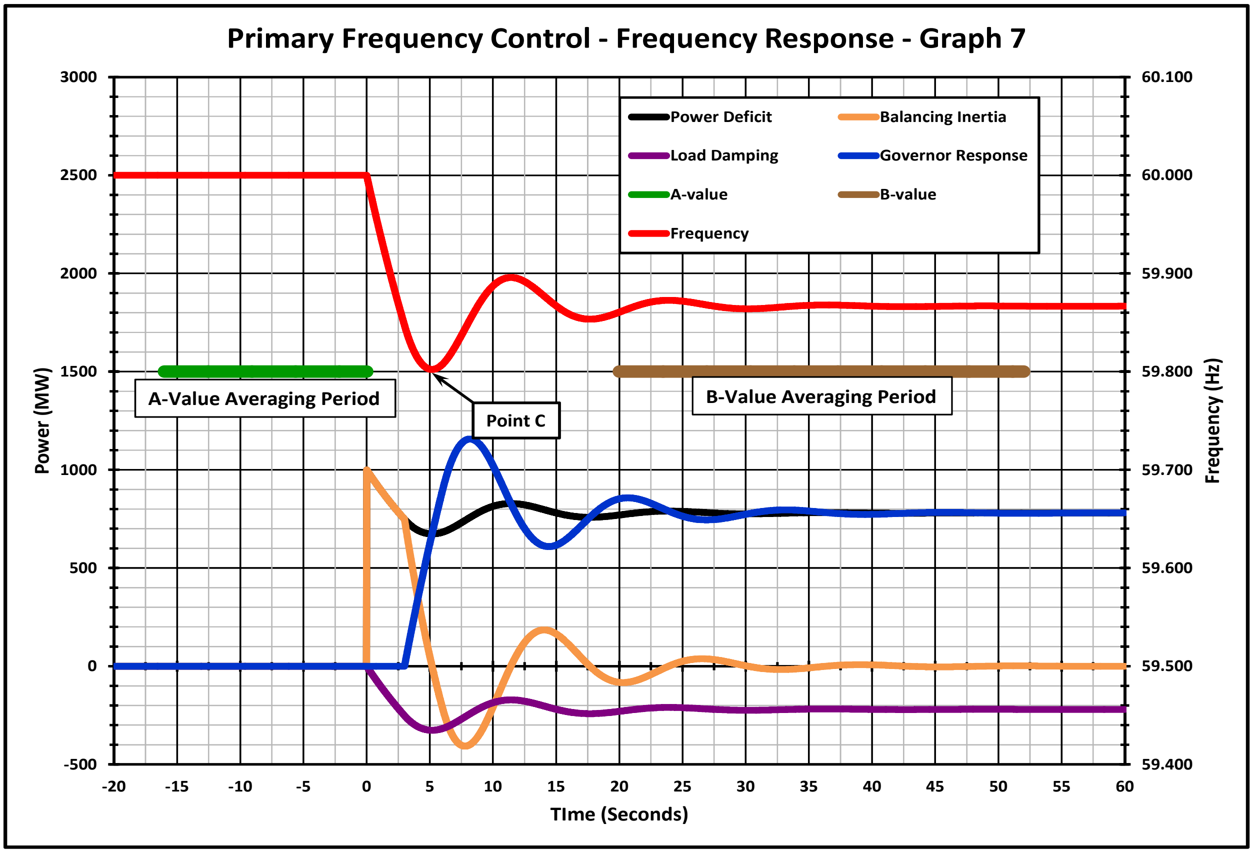
Once the frequency decline is arrested, the governors continue to respond because of the time delay associated with their Governor Response. This results in the frequency partially recovering from the minimum arrested value and results in an oscillating transient that follows the minimum frequency (arrested frequency) until power flows and frequency settle during the transient period that ends roughly 20 seconds after the Disturbance event. This post-disturbance transient period is included on the fifth illustrative graph, Primary Frequency Control – Frequency Response – Graph 5.



The total Disturbance event illustration is presented on the sixth graph, Primary Frequency Control – Frequency Response – Graph 6. Frequency and power contributions stabilize at the end of the transient period. Frequency Response calculated from data measured during this settled period is called the “Settled Frequency Response.” The Settled Frequency Response is the best measure to use as an estimator for the “Frequency Bias Setting” discussed later.



The final Disturbance event illustration is presented on the seventh graph, Primary Frequency Control – Frequency Response – Graph 7. This graph shows the averaging periods used to estimate the pre-disturbance A-Value averaging period and the post-disturbance B-Value averaging period used to calculate the settled frequency response. A discussion of the measurement of Frequency Response immediately follows these graphs. That discussion includes consideration of the factors that affect the methods chosen to measure Frequency Response for implementation in a reliability standard.



Frequency Response Measurement (FRM)

The classic Frequency Response points A, C, and B, shown below in Fig. 1 Frequency Response Characteristic, are used for measurement as found in the Frequency Response Characteristic Survey Training Document within the NERC operating manual, found at http://www.nerc.com/files/opman_7-1-11.pdf. This traditional Frequency Response Measure has recently been more specifically termed "**settled frequency response**." This term has been used because it provides the best Frequency Response Measure to estimate the Frequency Bias Setting in Tie-line Bias Control based Automatic Generation Control Systems. However, the industry has recognized that there is considerable variability in measurement resulting from the selection of Point A and Point B in the traditional measure making the traditional measurement method unsuitable as the basis for an enforceable reliability standard in a real world setting of multiple Balancing Authority interconnections.

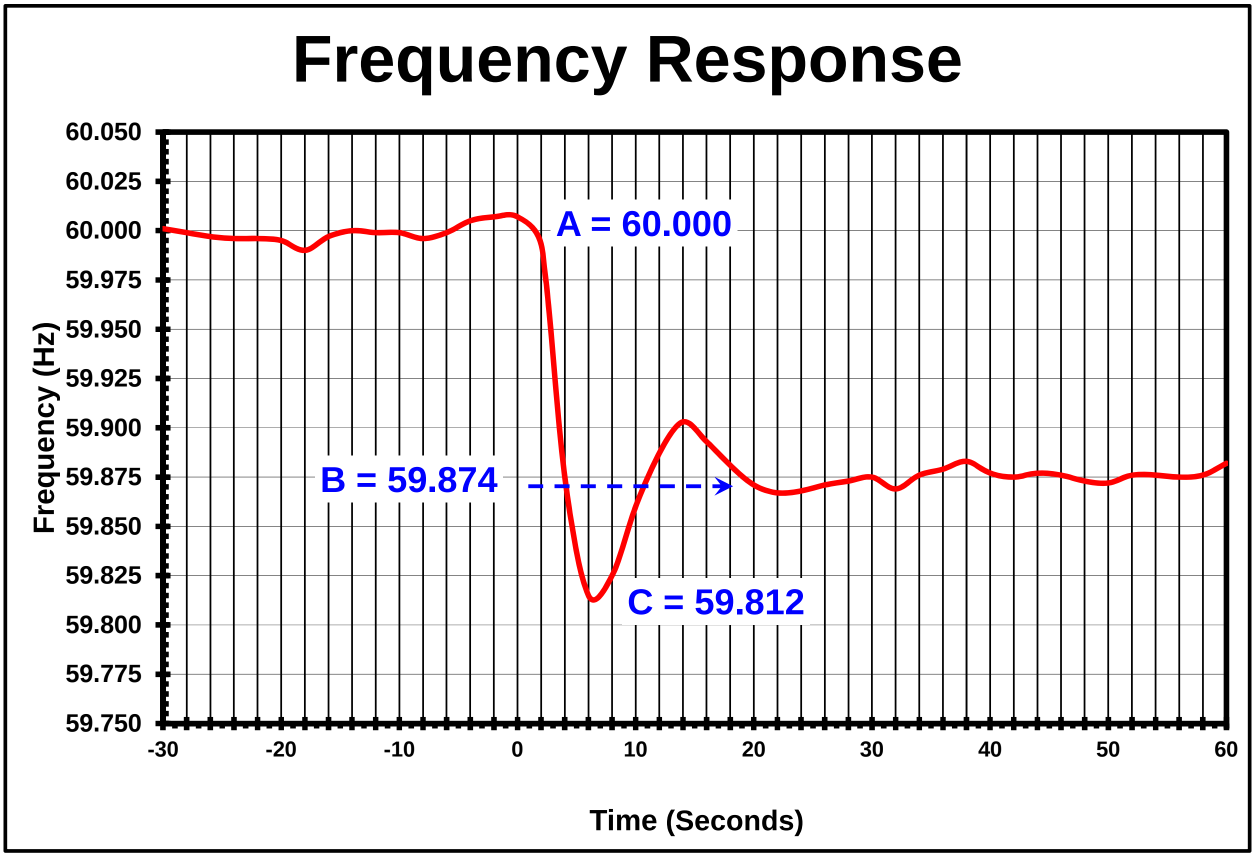


Figure 1. Frequency Response Characteristic

By contrast, measuring an Interconnection's settled frequency response is straightforward and fairly accurate. All that's needed to make the calculation is to know the size of a given contingency (MW), divide this value by the change in frequency and multiply the results by 10 since frequency response is expressed in MW/0.1Hz.

Measuring a BA's frequency response is more challenging. Prior to BAL-003-1, NERC's *Frequency Response Characteristic Survey Training Document* provided guidance to calculate Frequency Response. In short, it told the reader to identify the BA's interchange values "immediately before" and "immediately after" the Disturbance event and use the difference to calculate the MWs the BA deployed for the event. There are two challenges with this approach:

- Two people looking at the same data would come up with different values when assessing which exact points were immediately before and after the event.
- In practice, the actual response provided by the BA can change significantly in the window of time between point B and when secondary and tertiary control can assist in recovery.

Therefore, the measurement of settled frequency response has been standardized in a number of ways to limit the variability in measurement resulting from the poorly specified selection of Point A and Point B. It should be noted that t-0 has been defined as the first scan value that shows a deviation in frequency of some significance, usually approaching about 10 mHz. The goal is such that the first scan prior to t-0 was unaffected by the deviation and appropriate for one of the averaging points.

- The A-value averaging period of approximately the previous 16 seconds prior to t-0 was selected to allow for an averaging of at least 2 scans for entities utilizing 6 second scan rates. (All time average period references in this document are for 2 second scan rates unless noted otherwise.)
- The B-value averaging period of approximately (t+20 to t+52 seconds) was selected to attempt to obtain the average of the data after primary frequency response was deployed and the transient completed(settled), but before significance influence of secondary control. Multiple periods were considered for averaging the B-value:
    - 12 to 24 sec
    - 18 to 30 sec
    - 20 to 40 sec
    - 18 to 52 sec
    - 20 to 52 sec

  It is necessary for all BAs from an interconnection to use the same averaging periods to provide consistent results. In addition, the SDT decided that until more experience is gained, it is also desirable for all interconnections to use the same averaging periods to allow comparison between interconnections.

The methods presented in this document only address the values required to calculate the frequency response associated with the frequency change between the initial frequency, A-Value, and the settling frequency, B-Value. No reasonable or consistent calculations can be made relating to the arresting frequency, C-Value, using Energy Management System (EMS) scan rate data as long as 6-seconds or tie-line flow values associated with the minimum value of the frequency response characteristic (C-value) as measured at the BA level.

Both the calculation of the frequency at Point A and the frequency at Point B began with the assumption that a 6-second scan rate was the source of the data. Once the averaging periods for a 6-second scan rate were selected, the averaging periods for the other scan rates were selected to provide as much consistency as possible between BAs with different scan rates.

The Frequency at Point A was initially defined as the average of the two scans immediately prior to the frequency event. All other averaging periods were selected to be as consistent as possible with this 12 second average scan from the 6-second scan rate method. In addition, the "**actual net interchange immediately before Disturbance**" is defined as the average of the same scans as used for the Point A frequency average.

The Frequency at Point B was then selected to be an average as long as the average of 6-second scan data as possible that would not begin until most of the hydro governor response had been delivered and would end before significant Automatic Generation Control (AGC) recovery response had been initiated as indicated by a consistent frequency restoration slope. The "**actual net interchange immediately after Disturbance**" is defined as the average of the same scans as used for the Point B frequency average.

B Averaging Period Selection:

Experience from the Electric Reliability Council of Texas ("ERCOT") and the field trail on other interconnections indicated that the 12 to 24 second and 18 to 30 second averaging periods were not suitable because they did not provide the consistency in results that the other averaging periods provided, and that the remaining measuring periods do not provide significantly different results from each other. The team believed that this was observed because the transients were not complete in all of the samples using these averaging periods.

The 18 to 52 second and 20 to 52 second averaging periods were compared to each other, with the 20 to 52 second period providing more consistent values, believed to result from the incomplete transient in some of the 18 to 52 second samples.

This left a choice between the 20 to 40 second and the 20 to 52 second averaging periods. The team recognized that there would be more AGC response in the 20 to 52 second period, but the team also recognized that the 20 to 52 second period would provide a better measure of squelched response from outer loop control action. The 20 to 52 second period was selected because it would indicate squelched response from outer-loop control and provide incentive to reduce response withdrawal. The final selections for the data averaging periods used in FRS Form 1 are shown in the table below.

Definitions of Frequency Values for Frequency Response Calculation

Scan Rate	T 0 Scan	A Value (average)	B Value (average)
6-Seconds	Identify first significant change in frequency as the T 0 scan	Average of T-1 through T-2 scans	Average of T+4 through T+8 scans
5-Seconds		Average of T-1 through T-2 scans	Average of T+5 through T+10 scans
4-Seconds		Average of T-1 through T-3 scans	Average of T+6 through T+12 scans
3-Seconds		Average of T-1 through T-5 scans	Average of T+7 through T+17 scans
2-Seconds		Average of T-1 through T-8 scans	Average of T+10 through T+26 scans

Consistent measurement of Primary Frequency Response is achievable for a selected number of events and can produce representative frequency response values, provided an appropriate sample size is used in the analysis. Available research investigating the minimum sample size to provide consistent measurements of Frequency Response has shown that a minimum sample size of 20 events should be adequate.

Measurement of Primary Frequency Response on an individual resource or load basis requires analysis of energy amounts that are often small and difficult to measure using current methods. In addition, the number of an interconnection's resources and loads providing their response could be problematic when compiling results for multiple events.

Measurement of Primary Frequency Response on an interconnection (System) basis is straight forward provided that an accurate frequency metering source is available and the magnitude of the resource/load imbalance is known in MWs.

Measurement on a Balancing Authority basis can be a challenge, since the determination of change in MWs is determined by the change in the individual BA's metered tie lines. Summation of tie lines is accomplished by summing the results of values obtained by the digital scanning of meters at intervals up to six seconds, resulting in a non-coincidental summing of values. Until the technology to GPS time stamp tie line values at the meter and the summing of those values for coincidental times is in use throughout the industry, it is necessary to use averaging of values described above to obtain consistent results.

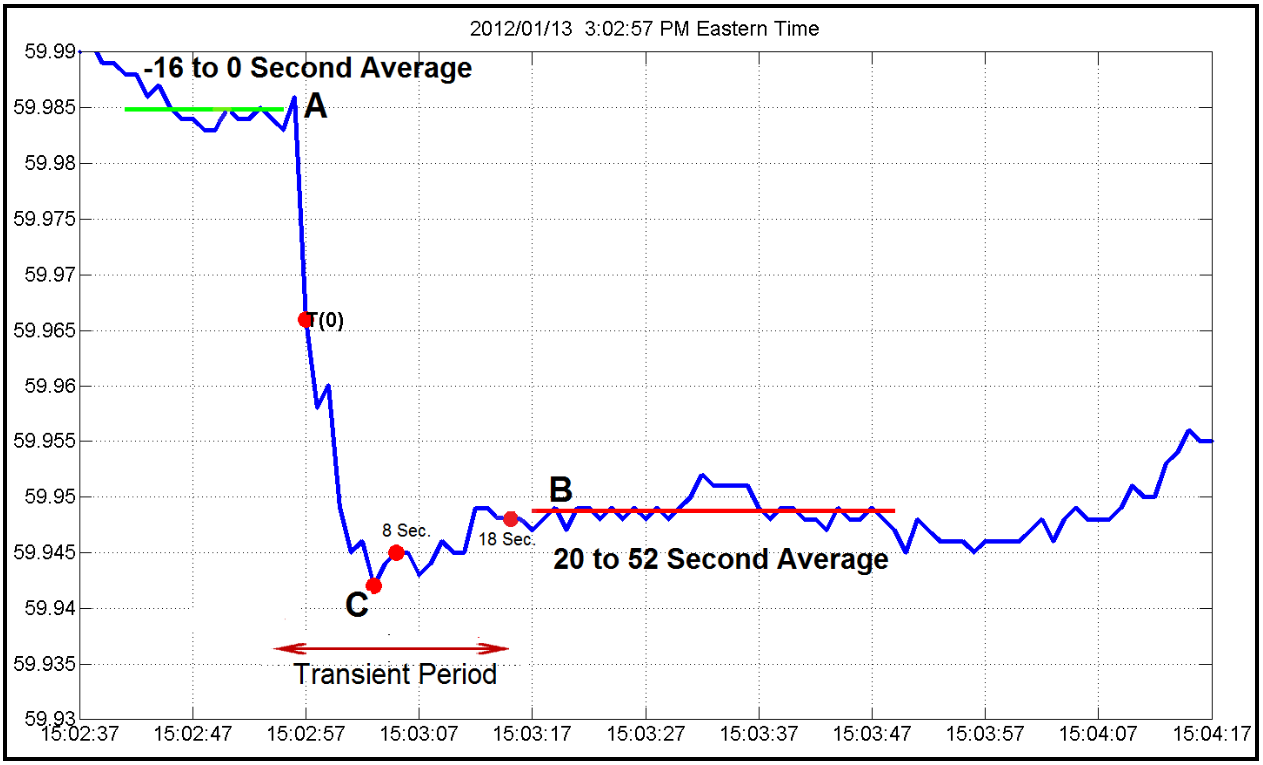


Figure 2. Frequency Response Measurement

The standardized measure is shown graphically in Fig. 2 Frequency Response Measurement with the averaging periods shown by the solid green and red lines on the graph. Since FERC directed a performance obligation for BAL-003-1, it is important to be more objective in the measurement process. The standardized calculation is available on FRS Form 2 for EMS scan rates of 2, 3, 4, 5, and 6 seconds at http://www.nerc.com/filez/standards/Frequency_Response.html.

Arrested Frequency Response

There is another measure of Frequency Response that is of interest when developing a Frequency Response estimate that not only will be used for estimating the Frequency Bias Setting, but will also be used to assure reliability by operating in a manner that will bound interconnection frequency and prevent the operation of Under-frequency Relays. This Frequency Response Measure has recently been named "**arrested frequency response.**" This Frequency Response is significantly affected by the inertial Frequency Response, the governor Frequency Response and the time delays associated with the delivery of governor Frequency

Response. It is calculated by using the change in frequency between the initial frequency, A, and the maximum frequency change during the event, C, instead of using the change between A and B. Arrested Frequency Response is the correct response for determining the minimum Frequency Response related to under-frequency relay operation and the support of interconnection reliability. This is because it can be used to provide a direct estimate of the maximum frequency deviation an interconnection will experience for an initial frequency and a given size event in MW. Unfortunately, arrested frequency response cannot currently be measured using the existing EMS-based measurement infrastructure. This limitation exists because the scan rates currently used in industry EMSs are incapable of measuring the net actual interchange at the same instant that the maximum frequency deviation is reached. Fortunately, the ratio of arrested frequency response and settled frequency response tends to be stable on an interconnection. This allows the settled frequency response value to be used as a surrogate for the arrested frequency response and implement a reasonable measure upon which to base a standard. One consequence of using the settled frequency response as a surrogate for the arrested frequency response is the inclusion of a large reliability margin in Interconnection Frequency Response Obligation to allow for the difference between the settled frequency response as measured and the arrested frequency response that indicates reliability.

As measurement infrastructure improves one might expect the Frequency Response Obligation to transition to a measurement based directly on the arrested frequency response while the Frequency Bias Setting will continue to be based on the settled frequency response. However, at this time, the measurement devices and methods in use do not support the necessary level of accuracy to estimate arrested frequency response contribution for an individual Balancing Authority.

Frequency Response Definition and Examples

Limitations of the measurement infrastructure determine the measurement methods recommended in this standard. The measurement limitations provide opportunities to improve the Frequency Response as measured in the standard without contributing to an improvement in Frequency Response that contributes to reliability. These definitions and examples provide a basis for determining which contributions to Frequency Response contribute the most to improved reliability. They also provide the basis for determining on a case by case basis whether the individual contributors to the Frequency Response Measure are also contributing to reliability.

General Frequency Response Characteristics

In the simplest case Frequency Response includes any automatic response to changes in local frequency. If that response works to decrease that change in frequency, it is beneficial to reliability. If that response works to increase that change in frequency, it is detrimental to reliability. However, this definition does not address the relative value of one response as compared to other responses that may be provided in a specific case.

There are numerous characteristics associated with the Frequency Response that affect the reliability value and economic value of the response. These characteristics include:

1. **Inertial** – the response is inertial or approximates inertial response

Inertial response provides power without delay that is proportional to the frequency and the change in frequency. Therefore, power provided by electronic control as synthetic Inertial response must be proportional to the frequency and change in frequency and be provided without a time delay.

2. **Immediate** – no unnecessary intentional time delays or reduction in the rate of response delivery
    a. time delay before the beginning of the response
    Turbines that convert heat or kinetic energy have time delays related to the time delay from the time that the control valves are moved to initiate the change in power and the time that the power is delivered to the generator. These times are usually associated with the time it takes a change in mass flow to travel from the control valve to the first blades of the turbine in the turbine generator.
    b. reduction in the rate of response delivery
    There are natural delays associated with the rate of response delivery that are related to the mass flow travel from the first turbine blades to the last turbine blades. In addition, some turbines have intentional delays designed into the control system to slow the rate of change in the delivery of the kinetic energy or fuel to the turbine to prevent the turbine or other equipment from being damaged, hydro turbines, or to prevent the turbine from tripping due to excessive rate of change, gas turbines.
3. **Proportional** – the amount of the total response is proportional to the frequency error
    a. No Deadband – the response is proportional across the entire frequency range
    b. Deadband – the response is only proportional outside of a defined deadband
4. **Bi-directional** – the response occurs to both increases and decreases in frequency
5. **Continuous** – there are no discontinuities in the delivery of the response (no step changes)
6. **Sustained** – the response is sustained until frequency is returned to schedule

Frequency Response Reliability Value

This section contains a more detailed discussion of the various characteristics of Frequency Response listed in the previous section. It also provides an indication of the relative value of these characteristics with respect to their contribution to reliability. Finally, it includes some examples of the described responses.

Inertial Response is provided from the stored energy in the rotating mass of the turbine-generators and synchronous motors on the interconnection. It limits the rate of change of frequency until sufficient Frequency Response can be supplied to arrest the change in frequency. Its reliability value increases as the time delay associated with the delivery of other Frequency Response on the interconnection increases. If those time delays are minimal, then the value of inertial response is low. If all time delays associated with the Frequency Response could be eliminated, then inertial response would have little value.

The reliability value of Inertial Response is the greatest on small interconnections because the size of the Disturbance events is larger relative to the inertia of the interconnection. Electronic controls have been developed to provide synthetic inertial response from the stored energy in asynchronous generators to supplement the natural inertial response. Some Type III & IV Wind Turbines have this capability. In addition, electronically controlled SCRs have been developed that can store energy in the electrical system and release this stored energy to supply synthetic inertial response when required.

Immediate Response is provided by load damping and because the time delays associated with its delivery are very short (related to the speed of electrical signal in the electrical system); load damping requires very little inertial response to limit arrested frequency effectively. Synthetic immediate response can also be supplied from loads because in many cases, there is no mass flow time delay associated with the load process providing the power and energy reduction. Therefore, loads can provide an immediate response with a higher reliability value than generators with time delays required by the physics of the turbine-generator.

Governor response has time delays associated with its delivery. Governor response provided with shorter time delays has a higher reliability value because those shorter time delays require less inertial response to arrest frequency. Governor response is provided by the turbine-generators on the interconnection. Time delays associated with governor response vary depending on the type of turbine-generator providing the response.

The longest time delays are usually associated with high head hydro turbine-generators that require long times from the governor action until the additional mass flow through the turbine. These units may also have the longest delivery time associated with the full delivery of response because of the timing designed into the governor response.[5]

Intermediate time delays are usually associated with steam turbine-generators. The response begins when the steam control valves are adjusted and the steam mass flows from the valves to the first high pressure turbine blades. The delivery times associated with the full delivery of response may require the steam to flow through high, intermediate and low pressure turbines including reheat flows before full power is delivered. These times are shorter than those of the hydro turbine-generators in general, but not as fast as the times associated with gas turbines.[6]

Gas turbines typically have the shortest time delays, because control is provided by injecting more or less fuel into the turbine combustor and adjusting the air control dampers. These control changes can be initiated rapidly and the mass flow has the shortest path to the turbine

[5] Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns – Final Report, IEEE, May 2007, pp. 1-6 – 1-9.

[6] Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns – Final Report, IEEE, May 2007, pp. 1-4 – 1-6.

blades. There may be timing limitations related to the rate of change in output of the gas turbine-generator to maintain flame stability in some cases slowing the rate of change.[7]

Synthetic Governor Response can be supplied by certain loads and storage systems. The immediacy of the response is normally limited only by the electronic controls used to activate the desired response. Synthetic response, when it can be supplied immediately without significant time delay, has a higher reliability value because it requires less inertial response to achieve smaller arrested frequency deviations.

Proportional Response indicates that the response provided is proportional in magnitude to the frequency error. Response deadbands cause a non-proportional response and reduce the value of the response with respect to reliability. Contrary to general consensus, deadbands do not reduce the amount of Frequency Response that must be provided, they only transfer the responsibility for providing that Frequency Response from one source on the interconnection to another. For a given response, the response with the smaller deadband has the greater reliability value. Therefore, deadbands should be set to the smallest value that supports overall reliable operation including the reliable operation of the generator.

Electronic controls have also been developed to provide synthetic governor response. When these controls are applied to certain loads or stored energy systems, they can be programmed to provide synthetic governor response similar to the proportional response of a turbine-generator governor. Governor response in generators is limited to a small percentage of the output of the generating unit, while synthetic governor response could be applied to much larger percentages of loads or storage devices providing such response.

Load damping provides a proportional response.

Continuous Response is response that has no discontinuous (step) changes in the frequency versus response curve. Step changes (Non-continuous Response) in the Governor Response curve can lead to frequency instabilities at frequencies near the changes. The ERCOT Interconnection observed this and has since prohibited the use of governor response characteristics incorporating step responses.

Step responses also occur with the implementation of load interruption using under-frequency or over-frequency relays.

Bi-directional Response is response that occurs in both directions, when the frequency is increasing and when the frequency is decreasing. A uni-directional response is a response that only occurs once when frequency is decreasing or when frequency is increasing.

Inertial response, governor response and load damping are all bi-directional responses. Certain loads are capable of providing proportional bi-directional response while others are only capable of providing non-proportional bi-directional response.

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[7] Interconnected Power System Response to Generation Governing: Present Practice and Outstanding Concerns – Final Report, IEEE, May 2007, pp. 1-16 – 1-19.

The ERCOT Load Resource program is a uni-directional response program. Loads are only tripped when frequency declines below a given set-point. When frequency is restored above that set-point, the loads must be manually reconnected. As a consequence, the Frequency Response only occurs once with declining frequency and does not oppose the increase in frequency after the initial decline. If there should be a frequency oscillation, the uni-directional response will not contribute to the opposition of a second frequency decline across the set-point during an oscillation event. Once a uni-directional response has occurred, it is unavailable for a second decline before reset.

Step or proportional responses implemented bi-directionally can lead to frequency instability when there is less continuous frequency response than the magnitude of the change in continuous response between the trip and reset frequencies in step, or the proportional response rate of change is greater than the underlying continuous response. A step bi-directional response will have the load reconnected as frequency recovers from the event thus opposing the increase in frequency during recovery, and also resetting the load response for the next frequency decline automatically. Bi-directional response obviously has a greater reliability value than uni-directional response.

Sustained Response is provided at its full value until frequency is restored to its scheduled value. On today's interconnections, few frequency responses are fully sustained until frequency has been restored to its scheduled value. On steam based turbine-generators, the steam pressure may drop after a time as the result of the additional steam flow from governor action. However, in general this has not been a problem because most responses are incomplete at the time that frequency has been initially arrested and the additional response has generally been sufficient to make up for more than the these unpreventable reductions in response. However, the intentional withdrawal of response before frequency has been restored to schedule can cause a decline in frequency beyond that which would be otherwise expected. This intentional withdrawal of response is highly detrimental to reliability. Therefore, it can be concluded in general that sustained response has a higher reliability value than un-sustained response.

On an interconnection, the withdrawal of response due to the loss of steam pressure on the steam units may be offset by the slower response of hydro turbine-generators. In these cases, the reliability of the combined response provides a greater reliability value than the individual response of each type. The steam turbine-generators provide a fast response that may be reduced, while the hydro turbine-generators provide a slower response, contributing less to the arresting response, offsetting any reduction by the steam turbine-generators to assure a sustained response.

Sustained Response must also be considered for any resource that has a limited duration associated with its response. The amount of stored energy available from a resource may limit its ability to sustain response for a duration of time necessary to support reliability.

Frequency Response Cost Factors

In every system of exchange there are two sides; the supply side and the demand side. The supply side provides the services used by the demand side. In the case of Frequency Response, the supply side includes all providers of Frequency Response and the demand side includes all participants that create the need for Frequency Response.

Frequency Response Costs – Supply Side

There are a number of factors that affect the cost of providing Frequency Response from resources. Since there is a cost associated with those factors, some method of appropriate compensation could be made available to those resources providing Frequency Response. Without compensation, providers of Frequency Response will be put in the position of incurring additional cost that can be avoided only by reducing or eliminating the response they provide. These costs are incurred independently of whether provided for in a formal Regional Transmission Organization/Independent System Operator (RTO/ISO) market or in a traditional BA subject to the FERC pro-forma tariffs.

It is the responsibility of the BA or the RTO/ISO to acquire the necessary amount of Frequency Response to support reliability in the most cost effective manner. This function is performed best when the suppliers are evaluated based on the value of the Frequency Response they provide and compensated appropriately for that Frequency Response. Suppliers provide Frequency Response when they are assured that they will receive fair compensation. Before considering how to perform this evaluation and compensation, the costs associated with providing Frequency Response should be understood and evaluated with respect to the level of reliability they offer.

Some cost factors that have been identified for providing Frequency Response include:

1. **Capacity Opportunity Cost** – the costs, including opportunity costs, associated with reserving capacity to provide Frequency Response. These costs are usually associated with the alternative use of the same capacity to provide energy or other ancillary services. There may also be capacity opportunity costs associated with the loss in average capacity by a load providing Frequency Response.
2. **Fuel Cost** – The cost of fuel used to provide the Frequency Response. The costs for fuel to provide Frequency Response can result in energy costs significantly different from the system marginal energy cost, both higher and lower. This is the case when Frequency Response is provided by resources that are not at the system marginal cost.
3. **Energy Efficiency Penalty Costs** – the costs associated with the loss in efficiency when the resource is operated in a mode that supports the delivery of Frequency Response. This cost is usually in the form of additional fuel use to provide the same amount of energy. An example is the difference between operating a steam turbine in valve control mode with an active governor and sliding pressure mode with valves wide open and no active governor control except for over-speed. This cost is incurred for all of the energy provided by the resource, not just the energy provided for Frequency Response. There may be additional energy costs associated with a load providing Frequency Response from loss in efficiency of their process when load is reduced.
4. **Capacity Efficiency Penalty Costs** – the costs associated with any reduction in capacity resulting from the loss of capacity associated with the loss in energy efficiency. When efficiency is lost, capacity may be lost at the same time because of limitations in the amount of input energy that can be provided to the resource.

5. **Maintenance Costs** – the operation of the resource in a manner necessary to provide Frequency Response may result in increases in the maintenance costs associated with the resource.
6. **Emissions Costs** – the additional costs incurred to manage any additional emissions that result when the resource is providing Frequency Response or stands ready to provide Frequency Response.

A good contract for the acquisition of Frequency Response from a resource will provide appropriate compensation to the resource for all of the costs the resource incurs to provide Frequency Response. It will also provide a method to evaluate the least cost mix of resources necessary to provide the minimum required Frequency Response for maintaining reliability. Finally, it will provide the least complex method of evaluation considering the complexity and efficiency of the acquisition process.

Frequency Response Costs – Demand Side

Not only are there costs associated with acquiring Frequency Response from the supplying resources, there are costs associated with the amount of Frequency Response that must be acquired and influenced by those participants that create the need for Frequency Response. If the costs of acquiring Frequency Response from the supply resources can be assigned to those parties that create the need for Frequency Response, there is the promise that the amount of Frequency Response required to maintain reliability can be minimized. The considerations are the same as those that are driving the development of "real time pricing" and "dynamic pricing". If the costs are passed on to those contributing to the need for Frequency Response, incentives are created to reduce the need for Frequency Response making interconnection operations less expensive and more reliable. The problem is to balance both cost and complexity against reliability on both the supply side and the demand side.

Rationale by Requirement

Requirement 1

R1. Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or Balancing Authority that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation.

Background and Rationale

R1 is intended to meet the following primary objectives:

- Determine whether a Balancing Authority (BA) has sufficient Frequency Response for reliable operations.
- Provide the feeder information needed to calculate CPS limits and Frequency Bias Settings.

Primary Objective

With regard to the first objective, FRS Form 1 and the process in Attachment A provide the method for determining the Interconnections' necessary amount of Frequency Response and allocating it to the Balancing Authorities. The field trial for BAL-003-1 is testing an allocation methodology based on the amount of load and generation in the BA. This is to accommodate the wide spectrum of BAs from generation-only all the way to load-only.

Frequency Response Sharing Groups (FRSGs)

This standard proposes an entity called FRSG, which is defined as:

> *A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members.*

This standard allows Balancing Authorities to cooperatively form FRSGs as a means to jointly meet the FRS. There is no obligation to form or be a part of FRSGs. The members of the FRSG would determine how to allocate sanctions among its members. This standard does not mandate the formation of FRSGs, but allows them as a means to meet one of FERC's Order No. 693 directives.

FRSG performance may be calculated one of two ways:

- Calculate a group NI_A and measure the group response to all events in the reporting year on a single FRS Form 1, or
- Jointly submit the individual BAs' Form 1s, with a summary spreadsheet that sums each participant's individual event performance.

Frequency Response Obligation and Calculation

The basic Frequency Response Obligation is based on annual load and generation data reported in FERC Form 714 (where applicable, see below for non-jurisdictional entities) for the previous full calendar year. The basic allocation formula used by NERC is:

$$\mathrm{FRO_{BA}} = \mathrm{FRO_{Int}} \times \frac{\text{Annual Gen}_{\mathrm{BA}} + \text{Annual Load}_{\mathrm{BA}}}{\text{Annual Gen}_{\mathrm{Int}} + \text{Annual Load}_{\mathrm{Int}}}$$

Where:

- Annual Gen_{BA} is the annual "Net Generation (MWh)", FERC Form 714, line 13, column c of Part II - Schedule 3.
- Annual Load_{BA} is the annual "Net Energy for Load (MWh)", FERC Form 714, line 13, column e of Part II - Schedule 3.
- Annual Gen_{Int} is the sum of all Annual Gen_{BA} values reported in that interconnection.
- Annual Load_{Int} is the sum of all Annual Load_{BA} values reported in that interconnection.

Balancing Authorities that are not FERC jurisdictional should use the Form 714 Instructions to assemble and submit equivalent data. Until the BAL-003-1 process outlined in Attachment 1 is implemented, Balancing Authorities can approximate their FRO by multiplying their Interconnection's FRO by their share of Interconnection Bias. The data used for this calculation should be for the most recently filed Form 714. As an example, a report to NERC in January 2013 would use the Form 714 data filed in 2012, which utilized data from 2011.

Balancing Authorities that merge or that transfer load or generation need to notify the ERO of the change in footprint and corresponding changes in allocation such that the net obligation for the Interconnection remains the same and so that CPS limits can be adjusted.

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.

With regard to the second objective above (determining Frequency Bias Settings and CPS limits), Balancing Authorities have been asked to perform annual reviews of their Frequency Bias Settings by measuring their Frequency Response, dating back to Policy 1. This obligation was carried forward into BAL-003-01.b. While the associated training document provided useful information, it left many of the details to the judgment of the person doing the analysis. The FRS Form 1 and FRS Form 2 provide a consistent, objective process for calculating Frequency Response to develop an annual measure, the FRM.

The FRM will be computed from Single Event Frequency Response Data (SEFRD), defined as: "the data from an individual event from a Balancing Authority that is used to calculate its Frequency Response, expressed in MW/0.1Hz". The SEFRD for a typical Balancing Authority in an Interconnection with more than one Balancing Authority is basically the change of its net actual interchange on its tie lines with its adjacent Balancing Authorities divided by the change in interconnection frequency. (Some Balancing Authorities may choose to apply corrections to their net actual interchange values to account for factors such as nonconforming loads. FRS Form 1 shows the types of adjustments that are allowed.)

A standardized sampling interval of approximately 20 to 52 seconds will be used in the computation of SEFRD values. Microsoft Excel® spreadsheet interfaces for EMS scan rates of 2 through 6 seconds are provided to support the computation.

Single Event Frequency Response Data[8]

The use of a "single event measure" was considered early in the development of the FRS for compliance because a single event measure could be enforced for each event on the interconnection making compliance enforcement a simpler process. The variability of the measurement of Frequency Response for an individual BA for an individual Disturbance event was evaluated to determine its suitability for use as a compliance measure. The individual Disturbance events were normalized and plotted for each BA on the Eastern and Western Interconnections. This data was plotted with a dot representing each event. Events with a measured Frequency Response above the FRO were shown as blue dots and events with a measured Frequency Response below the FRO were shown as red dots. In order to show the full variability of the results the plots have been provided with two scales, a large scale to show all of the events and small scale to show the events closer to the FRO or a value of 1.0. This data is presented on four charts titled Frequency Response Events as Normalized by FRO.

Analysis of this data indicates a single event based compliance measure is unsuitable for compliance evaluation when the data has the large degree of variability shown in these charts. Based on the field trial data provided, only 3 out of 19 BAs on the Western Interconnection would be compliant for all events with a standard based on a single event measure. Only 1 out of 31 BAs on the Eastern Interconnection would be compliant for all events with a standard based on a single event measure. The general consensus of the industry is that there is not a reliability issue with insufficient Frequency Response on any of the North American Interconnections at this time. Therefore, it is unreasonable to even consider a standard that would indicate over 90% of the BAs in North American to be non-compliant with respect to maintaining sufficient Frequency Response to maintain adequate reliability.

In an attempt to balance the workload of Balancing Authorities with the need for accuracy in the FRM, the standard will require at least 20 samples selected during the course of the year to compute the FRM. Research conducted by the FRSDT indicated that a Balancing Authority's FRM will converge to a reasonably stable value with at least 20 samples.

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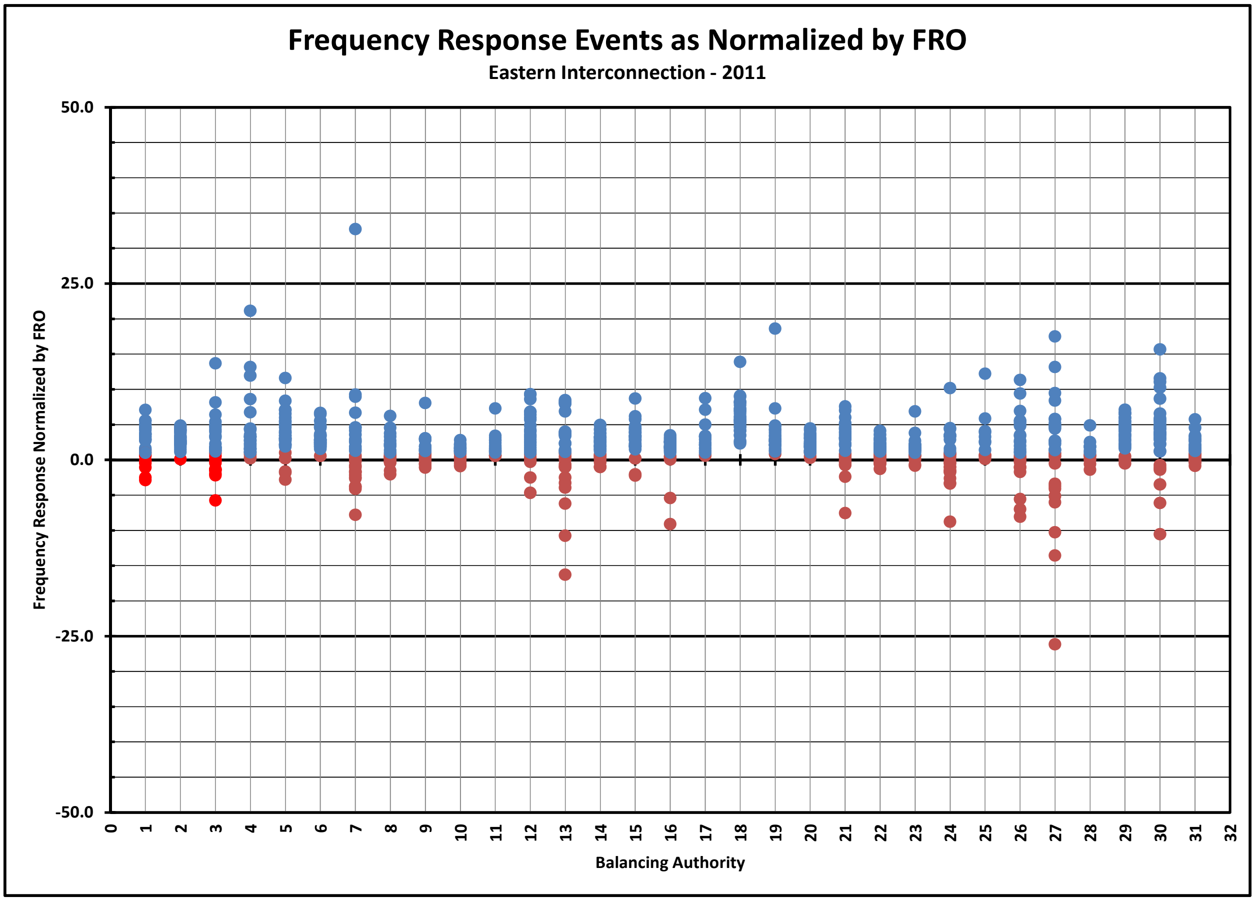
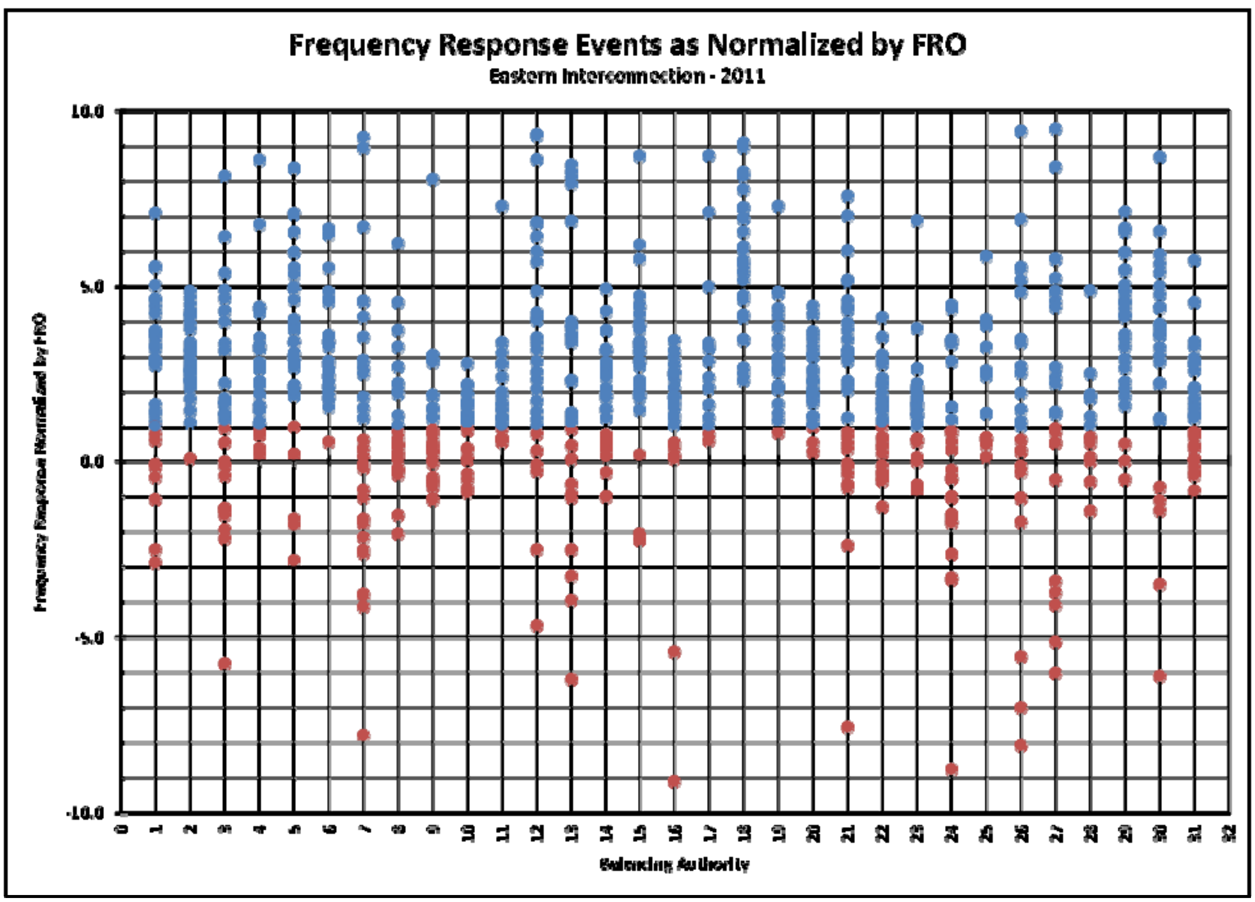
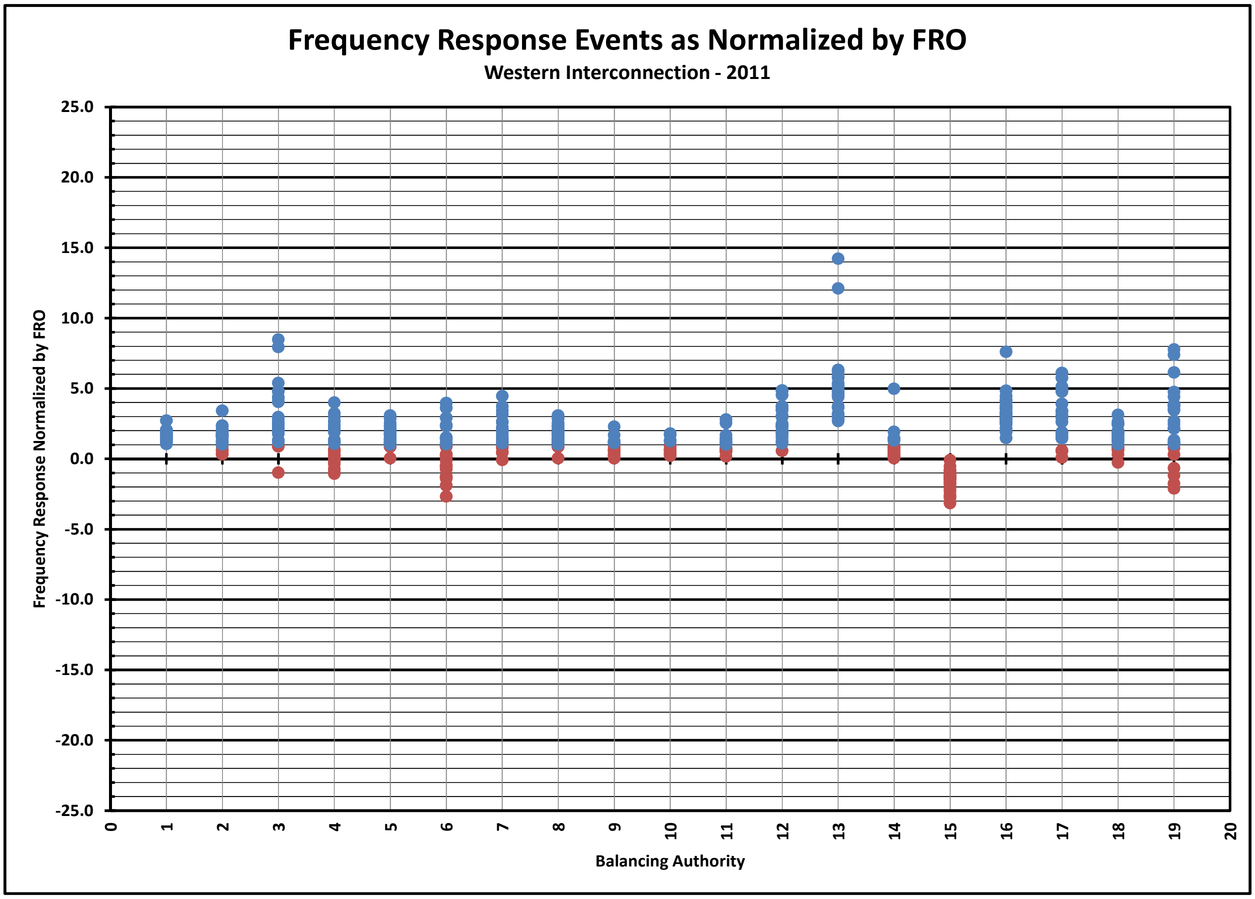
8 Single Event Analysis based on results of Frequency Response Standard Field Trial Analysis, September 17, 2012.



Frequency Response Events as Normalized by FRO
Eastern Interconnection - 2011
50.0
25.0
0.0
-25.0
-50.0
Frequency Response Normalized by FRO
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32
Balancing Authority



Frequency Response Events as Normalized by FRO
Eastern Interconnection - 2011
10.0
5.0
0.0
-5.0
-10.0
Frequency Response Normalized by FRO
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32
Balancing Authority


Frequency Response Events as Normalized by FRO
Western Interconnection - 2011
Frequency Response Normalized by FRO
25.0
20.0
15.0
10.0
5.0
0.0
-5.0
-10.0
-15.0
-20.0
-25.0
0
1
2
3
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7
8
9
10
11
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13
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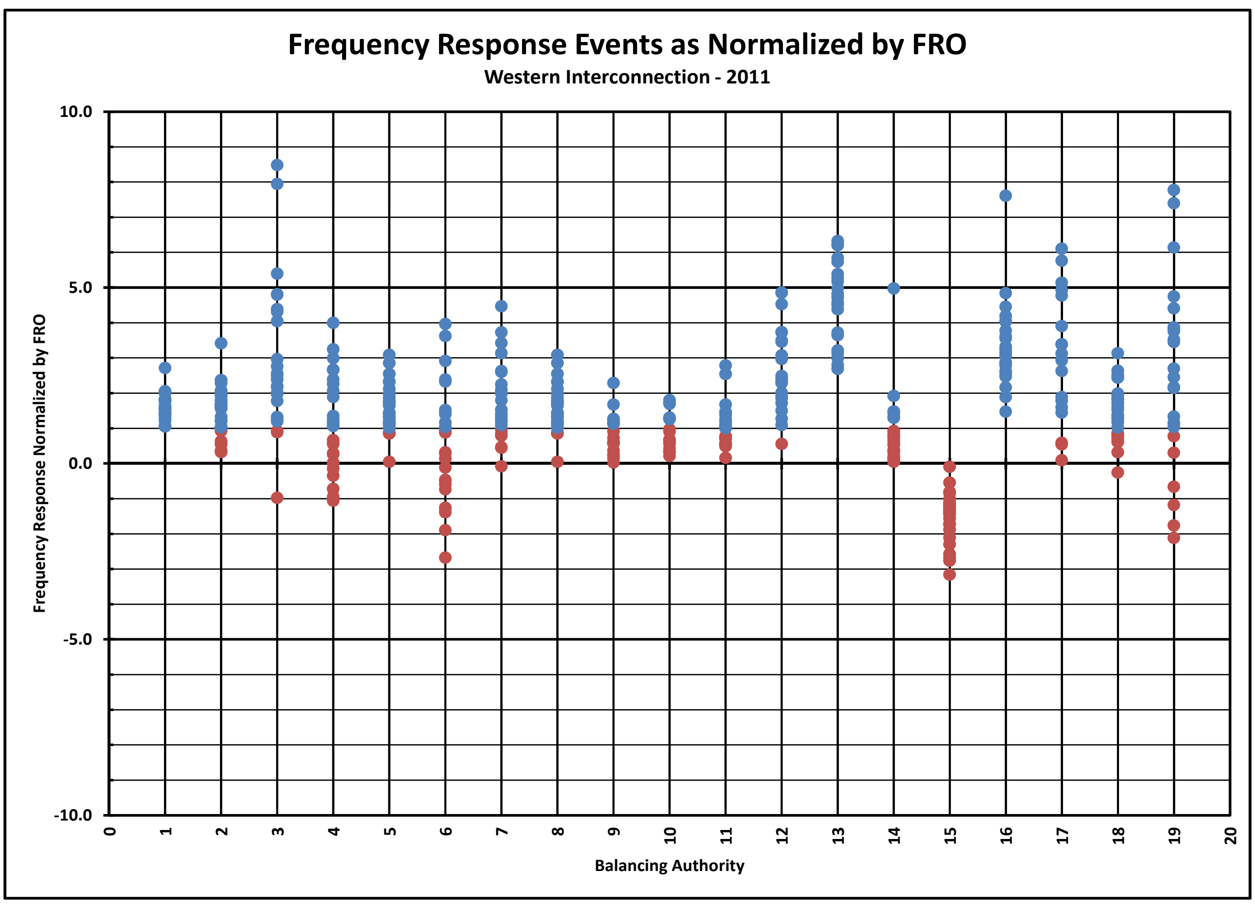
15
16
17
18
19
20
Balancing Authority


Frequency Response Events as Normalized by FRO
Western Interconnection - 2011
Frequency Response Normalized by FRO
10.0
5.0
0.0
-5.0
-10.0
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
Balancing Authority

Sample Size
In order to support field trial evaluations of sample size, sampling intervals, and aggregation techniques, the FRSDT will be retrieving scan rate data from the Balancing Authorities for each SEFRD. Additional frequency events may also be requested for research purposes, though they will not be included in the FRM computation.

FERC Order No. 693 directed the ERO (at P 375) to define the number of Frequency Response surveys that were conducted each year and to define a necessary amount of Frequency Response. R1 addresses both of these directives:

- There is a single annual survey of at least 20 events each year.
- The FRM calculated on FRS Form 1 is compared by the ERO against the FRO determined 12 months earlier (when the last FRS Form 1 was submitted) to verify the Balancing Authority provided its share of Interconnection Frequency Response.

Median as the Standard's Measure of Balancing Authority Performance
The FRSDT evaluated different approaches for "averaging" individual event observations to compute a technically sound estimate of Frequency Response Measure. The MW contribution for a single BA in a multi-BA Interconnection is small compared to the minute to minute changes in load, interchange and generation. For example, a 3000 MW BA in the Eastern Interconnection may only be called on to contribute 10MW for the loss of a 1000MW. The 10 MW of governor and load response may easily be masked as a coincident change in load.

In general, statisticians use the median as the best measure of central tendency when a population has outliers. Two independent reviews by the FRSDT has shown the Median to be less influenced by noise in the measurement process and the team has chosen the median as the initial metric for calculating the BAs' Frequency Response Measure.

The FRSDT performed extensive empirical studies and engaged in lively discussions in an attempt to determine the best aggregation technique for a sample set size of at least 20 events. Mean, median, and linear regression techniques were used on a trial basis with the data that was available during the early phases of the effort.

A key characteristic of the "aggregation challenge" is related to the use of actual net interchange data for measuring frequency response. The tie line flow measurements are varying continuously due to other operational phenomena occurring concurrently with the provision of frequency response. (*See* Appendix 1 for details.) All samples have "noise" in them, as most operational personnel who have computed the frequency response of their BA can attest. What has also become apparent to the FRSDT is that while the majority of the frequency response samples have similar levels of noise in them, a few of the samples may have much larger errors in them than the others that result in unrepresentative results. And with the sample set size of interest, it is common to have unrepresentative errors in these few samples to be very large and asymmetric. For example, one BA's subject matter expert observed recently that 4 out of 31 samples had a much larger error contribution than the other 27 samples, and that 3 out of 4 of the very high error samples grossly underestimated the frequency response. The median value demonstrated greater resiliency to this data quality problem than the mean with this data set. (The median has also demonstrated superiority to linear regression in the presence of these described data quality problems in other analyses conducted by the FRSDT, but the linear regression showed better performance than the mean.)

The above can be demonstrated with a relatively simple example. Let's assume that a Balancing Authority's true frequency response has an average value of -200 MW/ .1 Hz. Let's also assume that this Balancing Authority installed "special" perfect metering on key loads and generators, so that we could know the true frequency response of each sample. And then we will compare them with that measured by typical tie line flow metering, with the kind of noise and error that occurs commonly and "not so commonly". Let's start with the following 4 samples having a common level of noise, with MW/ .1 Hz as the unit of measurement.

Perfect measurement	Noise	Samples from tie lines
-190	-30	-220
-210	-20	-230
-220	10	-210
-180	20	-160
-200	Mean	-205
-200	Median	-215

Now let's add a fifth sample, which is highly contaminated with noise and error that grossly underestimates frequency response.

Perfect measurement	Noise	Samples from tie lines
-190	-30	-220
-210	-20	-230
-220	10	-210
-180	20	-160
-200	250	+50
-200	Mean	-154
-200	Median	-210

It is clear from the above simplistic example that the mean drops by about 25% while the median is affected minimally by the single highly contaminated value.

Based on the analyses performed thus far, the FRSDT believes that the median's superior resiliency to this type of data quality problem makes it the best aggregation technique at this time. However, the FRSDT sees merit and promise in future research with sample filtering combined with a technique such as linear regression.

When compared with the mean, linear regression shows superior performance with respect to the elimination of noise because the measured data is weighted by the size of the frequency change associated with the event. Since the noise is independent from frequency change, the greater weighting on larger events provides a superior technique for reducing the effect of noise on the results.

However, linear regression does not provide a better method when dealing with a few samples with large magnitudes of noise and unrepresentative error. There are only two alternatives to improve over the use of median when dealing with these larger unrepresentative errors:

1. Increase the sample size, or
2. Actively eliminate outliers due to unrepresentative error.

Unfortunately, the first alternative, increasing the sample size is not available because significantly more sample events are not available within the measurement time period of one year. Linear regression techniques are being investigated that have an active outlier elimination algorithm that would eliminate data that lie outside ranges of the 96th percentile and 99th percentile, for example.

Still, the use of linear regression has value in the context of this standard. The NERC Resources Subcommittee will use linear regression to evaluate Interconnection frequency response, particularly to evaluate trends, seasonal impacts, time of day influences, etc. The Good Practices and Tools section of this document outlines how a BA can use linear regression to develop a predictive tool for its operators.

Additional discussion on this topic is contained in "Appendix 1 – Data Quality Concerns Related to the Use of Actual Net Interchange Value" of this document.

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. A brief summary of the FRSDT majority consensus on the basis of each evaluation criterion is provided below.

- Provides two dimensional measurement – The FRSDT agrees that the two dimensional concept is a useful way to perceive frequency response characteristics, and that it may be useful for potential future modeling activities. Better data quality would increase support for such future efforts, and the use of the median for initial compliance evaluations within BAL-003-1 should not hinder any such effort. The FRSDT perceived this as a mild advantage for linear regression.
- Represents nonlinear characteristics – With considerations similar to those applied to the previous criterion, the FRSDT perceived this as a mild advantage for linear regression.
- Provides a single best estimator – The FRSDT gave minimal importance to the characteristic of the median averaging the middle values when used with an even number of samples.
- Is part of a linear system - With considerations similar to those applied to the first two criteria, the FRSDT perceived this as a mild advantage for linear regression (particularly in the modeling area.)
- Represents bimodal distributions – The FRSDT gave minimal weight of this criterion, as a change in Balancing Authority footprint does not seem to be addressed adequately by any aggregation technique.
- Quality statistics available – The FRSDT perceived this as a mild advantage for linear regression in that the statistics would be coupled directly to the compliance evaluation. The FRSDT also included this criterion as part of the modeling advantages cited above.

The FRSDT supports collecting data and performing quality statistical analysis. If it is determined that the use of the median, as opposed to a mean or linear regression aggregation, is yielding undesirable consequences, the FRSDT recommends that other aggregation techniques be re-evaluated at that time.

- Reducing influence of noise - This is the dominant concern of the FRSDT, and it perceives the median to have a major advantage over linear regression in addressing noise in the change in actual net interchange calculation. The FRSDT bases this judgment on: prior FRSDT studies that have shown that the median produces more stable results; the data used in the NERC Frequency Response Initiative document exhibits large quantities of noise; prior efforts of FRSDT members in performing frequency response sampling for their own Balancing Authorities over many years; and similar observations of noise in the CERTS frequency Monitoring Application. The FRSDT has serious concerns that the influence of noise has a greater tendency to yield a "false positive" compliance violation with linear regression than with the median. Also, limited studies performed by the FRSDT indicates the possibility that the resultant frequency response measure would yield more measurement variation across years with linear regression versus the median while the actual Balancing Authority performance remains unchanged.
- Reducing the influence of outliers – This is related to the previous criterion. The FRSDT recognizes four main sources of noise: concurrent operating phenomena (described elsewhere in this document), transient tie line flows for nearby contingencies, data acquisition time skew in tie line data measurements, and time skew and data compression issues in archiving techniques and tools such as PI. Some outliers may be caused in part by true variation in the actual frequency response, and it is desirable to include those in the frequency response measure. The FRSDT supports efforts in the near future to distinguish between outliers caused by noise versus true frequency response, and progress in this area may make it feasible and desirable to replace the median with linear regression, or some other validated technique. The FRSDT does note that this is a substantial undertaking, and it would require substantial input from a sufficient number of experts to help distinguish noise from true frequency response.
- Easy to calculate – The FRSDT perceives this to be a minor to moderate advantage for the median. However, more complex (but reasonably so) techniques would receive more support if clear progress can be made in noise elimination.
- Familiar indicator – The FRSDT perceives this to be a minor to moderate advantage for the median. However, more complex (but reasonably so) techniques would receive more support if clear progress can be made as a result of noise elimination.
- Currently used as a measure in BAL-003 – The present standard refers to an average and does not provide specific guidance on the computation of that average, but the FRSDT puts minimal weight on this evaluation criterion.

In summary, the FRSDT perceives an approximate balance between the modeling advantage for linear regression and the simplicity advantage of the median. However, the clear determinant in endorsing the use of the median is the data quality issue related to concurrent operational phenomena, transient tie line flows, and data acquisition and archiving limitations.

FERC Order No. 693 also directed the Standard (at P 375) to identify methods for Balancing Authorities to obtain Frequency Response. Requirement R1 allows Balancing Authorities to participate in Frequency Response Sharing Groups (FRSGs) to provide or obtain Frequency Response. These may be the same FRSGs that cooperate for BAL-002-0 or may be FRSGs that form for the purposes of BAL-003-1.

If BAs participate as an FRSG for BAL-003-1, compliance is based on the sum of the participants' performance.

Two other ways that BAs could obtain Frequency Response are through Supplemental Service or Overlap Regulation Service:

- No special action is needed if a BA provides or receives supplemental regulation. If the regulation occurs via Pseudo Tie, the transfer occurs automatically as part of Net Actual Interchange (NIA) and in response to information transferred from recipient to provider.
- If a BA provides overlap regulation, its FRS Form 1 will include the Frequency Bias setting as well as peak load and generation of the combined Balancing Authority Areas. The FRM event data will be calculated on the sum of the provider's and recipient's performance.

In the Violation Severity Levels for Requirement R1, the impact of a BA not having enough frequency response depends on two factors:

- Does the Interconnection have sufficient response?
- How short is the BA in providing its FRO?

The VSL takes these factors into account. While the VSLs look different than some other standards, an explanation would be helpful.

VSLs are a starting point for the enforcement process. The combination of the VSL and VRF is intended to measure a violation's impact on reliability and thus levy an appropriate sanction. Frequency Response is an interconnection-wide resource. The proposed VSLs are intended to put multi-BA Interconnections on the same plane as single-BA Interconnections.

Consider a small BA whose performance is 70% of its FRO. If all other BAs in the Interconnection are compliant, the small BA's performance has negligible impact on reliability, yet would be sanctioned at the same level as a BA who was responsible for its entire Interconnection. It is not rational to sanction this BA the same as a single BA Interconnection that had insufficient Frequency Response, because this would treat multi-BA Interconnections more harshly than single BA Interconnections on a significant scale.

The "Lower" and "Medium" VSLs say that the Interconnection has sufficient Frequency Response but individual BAs are deficient by small or larger amounts respectively. The High and Severe VSLs say the Interconnection does not meet the FRO and assesses sanctions based on whether the BA is deficient by a small or larger amount respectively.

Requirement 2

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 in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO.

Background and Rationale

Attachment A of the Standard discusses the process the ERO will follow to validate the BA's FRS Form 1 data and publish the official Frequency Bias Settings. Historically, it has taken multiple rounds of validation and outreach to confirm each BA's data due to transcription errors, misunderstanding of instructions, and other issues. While BAs historically submit Bias Setting data by January 1, it often takes one or more months to complete the process.

The target is to have BAs submit their data by January 10. The BAs are given 30 days to assemble their data since the BAs are dependent on the ERO to provide them with FRS Form 1, and there may be process delays in distributing the forms since they rely on identification of frequency events through November 30 of the preceding year.

Frequency Bias Settings generally change little from year to year. Given the fact that BAs can encounter staffing or EMS change issues coincident with the date the ERO sets for new Frequency Bias Setting implementation, the standard provides a 24 hour window on each side of the target date.

To recap the annual process:

1. The ERO posts the official list of frequency events to be used for this Standard in early December. The FRS Form 1 for each Interconnection will be posted shortly thereafter.

2. The Balancing Authority submits its revised annual Frequency Bias Setting value to NERC by January 10.

3. The ERO and the Resources Subcommittee validate Frequency Bias Setting values, perform error checking, and calculate, validate, and update CPS2 L10 values. This data collection and validation process can take as long as two months.

4. Once the L10 and Frequency Bias Setting values are validated, The ERO posts the values for the upcoming year and also informs the Balancing Authorities of the date on which to implement revised Frequency Bias Setting values. Implementation typically would be on or about March 1st of each year.

BAL-003-0.1b standard requires a minimum Frequency Bias Setting equal in absolute value to one percent of the Balancing Authority's estimated yearly peak demand (or maximum generation level if native load is not served). For most Balancing Authorities this calculated amount of Frequency Bias is significantly greater in absolute value than their actual Frequency Response characteristic (which represents an over-bias condition) resulting in over-control since a larger magnitude response is realized. This is especially true in the Eastern Interconnection where this condition requires excessive secondary frequency control response which degrades overall system performance and increases operating cost as compared to requiring an appropriate balance of primary and secondary frequency control response.

Balancing Authorities were given a minimum Frequency Bias Setting obligation because there had never been a mandatory Frequency Response Obligation. This historic "one percent of peak per 0.1Hz" obligation, dating back to NERC's predecessor, NAPSIC, was intended to ensure all BAs provide some support to Interconnection frequency.

The ideal system control state exists when the Frequency Bias Setting of the Balancing Authority exactly matches the actual Frequency Response characteristic of the Balancing Authority. If this is not achievable, over-bias is significantly better from a control perspective than under-bias with the caveat that Frequency Bias is set relatively close in magnitude to the Balancing Authority actual Frequency Response characteristic. Setting the Frequency Bias to better approximate the Balancing Authority natural Frequency Response characteristic will improve the quality and accuracy of ACE control, CPS & DCS and general AGC System control response. This is the technical basis for recommending an adjustment to the long standing "1% of peak/0.1Hz" Frequency Bias Setting. The Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard is intended to bring the Balancing Authorities' Frequency Bias Setting closer to their natural Frequency Response. Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard balances the following objectives:

- Bring the Frequency Bias Setting and Frequency Response closer together.
- Allow time to analyze impact on other Standards (CPS, BAAL and to a lesser extent DCS) by adjustments in the minimum Frequency Bias Setting, by accommodating only minor adjustments.
- Do not allow the Frequency Bias Setting minimum to drop below natural Frequency Response, because under-biasing could affect an Interconnection adversely.

Additional flexibility has been added to the Frequency Bias Setting based on the actual Frequency Response (FRM) by allowing the Frequency Bias Setting to have a value in the range from 100% of FRM to 125% of FRM. This change has been included for the following reasons:

- When the new standardized measurement method is applied to BAs with a Frequency Response close to the interconnection minimum response, the requirement to use FRM is as likely to result in a Frequency Bias Setting below the actual response as it is to result in a response above the actual response. From a reliability perspective, it is always better to have a Frequency Bias Setting slightly above the actual Frequency Response.

- As with single BA interconnections, the tuning of the control system may require that the BA implement a Frequency Response Setting slightly greater in absolute terms than its actual Frequency Response to get the best performance.
- The new standardized measurement method for determining FRM in some cases results in a measured Frequency Response significantly lower than the previous methods used by some BAs. It is desirable to not require significant change in the Frequency Bias Setting for these BAs that experience a reduction in their measured Frequency Response.

Requirement 3

R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection, is not receiving Overlap Regulation Service and utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is:

- *Less than zero at all times, and*
- *Equal to or more negative than its Frequency Response Obligation when the Frequency varies from 60 Hz by more that +/- 0.036 Hz.*

Background and Rationale

In multi-Balancing Authority interconnections, the Frequency Bias Setting should be coordinated among all BAs on the interconnection. When there is a minimum Frequency Bias Setting requirement, it should apply for all BAs. However, BAs using a variable Frequency Bias Setting may have non-linearity in their actual response for a number of reasons including the dead-bands implemented on their generator governors. The measurement to ensure that these BAs are conforming to the interconnection minimum is adjusted to remove the dead-band range from the calculated average Frequency Bias Setting actually used. For BAs using variable bias, FRS Form 1 has a data entry location for the previous year's average monthly Bias. The Balancing Authority and the ERO can compare this value to the previous year's Frequency Bias Setting minimum to ensure R3 has been met.

On single BA interconnections, there is no need to coordinate the Frequency Bias Setting with other BAs. This eliminates the need to maintain a minimum Frequency Bias Setting for any reason other than meeting the reliability requirement as specified by the Frequency Response Obligation.

Requirement 4

R4. 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 to either:

- *The sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or*
- *The Frequency Bias Setting as shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' Areas.*

Background and Rationale

This requirement reflects the operating principles first established by NERC Policy 1 and is similar to Requirement R6 of the approved BAL-003-0.1b standard. Overlap Regulation Service is a method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority's actual interchange, frequency response, and schedules into the providing Balancing Authority's AGC/ACE equation.

As noted earlier, a BA that is providing Overlap Regulation will report the sum of the Bias Settings in its FRS Form 1. Balancing Authorities receiving Overlap Regulation Service have an ACE and Frequency Bias Setting equal to zero (0).

How this Standard Meets the FERC Order No. 693 Directives

FERC Directive

The following is the relevant paragraph of Order No. 693.

> *Accordingly, the Commission approves Reliability Standard BAL-003-0 as mandatory and enforceable. In addition, the Commission directs the ERO to develop a modification to BAL-003-0 through the Reliability Standards development process that: (1) includes Levels of Non-Compliance; (2) determines the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other requirements of the Reliability Standard are being met, and to modify Measure M1 based on that determination and (3) defines the necessary amount of Frequency Response needed for Reliable Operation for each balancing authority with methods of obtaining and measuring that the frequency response is achieved.*

1. Levels of Non-Compliance

VRFs and VSLs are an equally effective way of assigning compliance elements to the standard.

2. Determine the appropriate periodicity of frequency response surveys necessary to ensure that Requirement R2 and other Requirements of the Reliability Standard are met

BAL-003 V0 R2 (the basis of Order No. 693) deals with the calculation of Frequency Bias Setting such that it reflects natural Frequency Response.

The drafting team has determined that a sample size on the order of at least 20 events is necessary to have a high confidence in the estimate of a BA's Frequency Response. Selection of the frequency excursion events used for analysis will be done via a method outlined in Attachment A to the Standard.

On average, these events will represent the largest 2-3 "clean" frequency excursions occurring each month.

Since Frequency Bias Setting is an annual obligation, the survey of the at least 20 frequency excursion events will occur once each year.

3. Define the necessary amount of Frequency Response needed for Reliable Operation for each Balancing Authority with methods of obtaining and measuring that the frequency response is achieved

Necessary Amount of Frequency Response

The drafting team has proposed the following approach to defining the necessary amount of frequency response. In general, the goal is to avoid triggering the first step of under-frequency load shedding (UFLS) in the given Interconnection for reasonable contingencies expected. The methodology for determining each Interconnection's and Balancing Authority's obligation is outlined in Attachment A to the Standard.

It should be noted the standard cannot guarantee there will never be a triggering of UFLS as the magnitude of "point C" differs throughout an interconnection during a disturbance and there are local areas that see much wider swings in frequency.

The contingency protection criterion is the largest reasonably expected contingency in the Interconnection. This can be based on the largest observed credible contingency in the previous 10 years or the largest Category C event for the Interconnection.

Attachment A to the standard presents the base obligation by Interconnection and adds a Reliability Margin. The Reliability Margin included addresses the difference between Points B and C and accounts for variables.

For multiple BA interconnections, the Frequency Response Obligation is allocated to BAs based on size. This allocation will be based on the following calculation:

$$\mathrm{FRO_{BA}} = \mathrm{FRO_{Int}} \times \frac{\text{Annual Gen}_{\mathrm{BA}} + \text{Annual Load}_{\mathrm{BA}}}{\text{Annual Gen}_{\mathrm{Int}} + \text{Annual Load}_{\mathrm{Int}}}$$

Methods of Obtaining Frequency Response

The drafting team believes the following are valid methods of obtaining Frequency Response:

- Regulation services.
- Contractual service. The drafting team has developed an approach to obtain a contractual share of Frequency Response from Adjacent Balancing Authorities. See FRS Form 1. While the final rules with regard to contractual services are being defined, the current expectation is that the ERO and the associated Region(s) should be notified beforehand and that the service be at least 6 months in duration.
- Through a tariff (e.g. Frequency Response and regulation service).
- From generators through an interconnection agreement.
- Contract with an internal resource or loads (The drafting team encourages the development of a NAESB business practice for Frequency Response service for linear (droop) and stepped (e.g. LaaR in Texas) response).

Since NERC standards should not prescribe or preclude any particular market related service, BAs and FRSGs may use whatever is most appropriate for their situation.

Measuring that the Frequency Response is Achieved

FRS Form 1 and the underlying data retained by the BA will be used for measuring whether Frequency Response was provided. FRS Form 1 will provide the guidance on how to account for and measure Frequency Response.

Going Beyond the Directive

Based on the combined operating experience of the SDT, the drafting team consensus is that each Interconnection has sufficient Frequency Response. If margins decline, there may be a need for additional standards or tools. The drafting team and the Resources Subcommittee are working with the ERO on its Frequency Response Initiative to develop processes and good practices so the Interconnections are prepared. These good practices and tools are described in the following section.

The drafting team is also evaluating a risk-based approach for basing the Interconnection Frequency Response Obligation on an historic probability density of frequency error, and for allocating the obligation on the basis of the Balancing Authority's average annual ACE share of frequency error. This allocation method uses the inverse of the rationale for allocating the CPS1 epsilon requirement by Bias share.

Good Practices and Tools

Background

This section outlines tips and tools to help Balancing authorities meet the Frequency Response Standard or to operate more reliably. If you have suggested additions, please send them to balancing@nerc.com.

Identifying and Estimating Frequency Responsive Reserves

Knowing the quantity and depth of frequency responsive reserves in real time is a possible next step to being better prepared for the next event. The challenge in achieving this is having the knowledge of the capabilities of all sources of frequency response. Presently the primary source of Frequency Response remains with the generation resources in our fleets.

Understanding how each of these sources performs to changes in system frequency and knowing their limitations would improve the BA's ability to measure frequency responsive reserves. Presently there are only guidelines, criteria and protocols in some regions of the industry that identify specific settings and performance expectations of Primary Frequency Response of resources.

One method of gaining a better understanding of performance is to measure performance during actual events that occur on the system. Measuring performance during actual events would only provide feedback for performance during that specific event and would not provide insight into depth of response or other limitations.

Repeated measurements will increase confidence in expected performance. NERC modeling standards are in process to be revised that will improve the BA's insight into predicting available frequency responsive reserves. However, knowing how resources are operated, what modes of operation provide sustained Primary Frequency Response and knowing the operating range of this response would give the BA the knowledge to accurately predict frequency response and the amount of frequency responsive reserves available in real time.

Some benefits have been realized by communicating to generation resources (GO) the importance of operating in modes that allow Primary Frequency Response to be sustained by the control systems of the resource. Other improvements in implementation of Primary Frequency Response have been achieved through improved settings on turbine governors through the elimination of "step" frequency response with the simultaneous reduction in governor dead-band settings.

Improvements in the full AGC control loop of the generating resource, which accounts for the expected Primary Frequency Response, have improved the delivery of quality Primary Frequency Response while minimizing secondary control actions of generators. Some of these actions can provide quick improvement in delivery of Primary Frequency Response.

Once Primary Frequency Response sources are known, the BA could calculate available reserves that are frequency responsive. Planning for these reserves during normal and emergency operations could be developed and added to the normal planning process.

Using FRS Form 1 Data

The information collected for this standard can be supplemented by a few data points to provide the Balancing Authority useful tools and information. The BA could do a regression analysis of its frequency response against the following values:

- Load (value A).
- Interchange (Value A).
- Total generation.
- Spinning reserve.

While the last two values above are not part of Form 1, they should be readily available. Small BAs might even include headroom on its larger generators as part of the regression.

The regression would provide a formula the BA could program in its EMS to present the operator a real time estimate of the BA's Frequency Response.

Statistical outliers in the regression would point to cases meriting further inspection to find causes of low Frequency Response or opportunities for improvement.

Tools

Single generating resource performance evaluation tools for steam turbine, combustion turbine (simple cycle or combined cycle) and for intermittent resources are available at the following link. http://texasre.org/standards_rules/standardsdev/rsc/sar003/Pages/Default.aspx.

These tools and the regional standard associated with them are in their final stages of development in the Texas region.

These tools will be posted on the NERC website.

References

NERC *Frequency Response Characteristic Survey Training Document* (Found in the NERC Operating Manual)

NERC Resources Subcommittee Position Paper on Frequency Response

NERC TIS Report *Interconnection Criteria for Frequency Response Requirements (for the Determination Interconnection Frequency Response Obligations (IFRO)*

Frequency Response Standard Field Trial Analysis, September 17, 2012

Appendix 1 - Data Quality Concerns Related To The Use Of The Actual Net Interchange Value

Actual net interchange for a typical Balancing Authority (BA) is the summation of its tie lines to other BAs. In some cases, there are pseudo-ties in it which reflect the effective removal or addition of load and/or generation from another BA, or it could include supplemental regulation as well. But in the typical scenario, actual net interchange values that are extracted from EMS data archiving can be influenced by data latency times in the data acquisition process, and also any timestamp skewing in the archival process.

Of greater concern, however, are the inevitable variations of other operating phenomena occurring concurrently with a frequency event. The impacts of these phenomena are superimposed on actual net interchange values along with the frequency response that we wish to measure through the use of the actual net interchange value.

To explore this issue further, let’s begin with the idealized condition:

- frequency is fairly stable at some value near or a little below 60 Hz
- ACE of the non-contingent BA of interest is 0 and has been 0 for an extended period, and AGC control signals have not been issued recently
- Actual net interchange is “on schedule”, and there are no schedule changes in the immediate future
- BA load is flat
- All generators not providing AGC are at their targets
- Variable generation such as wind and solar are not varying
- Operators have not directed any manual movements of generation recently

And when the contingency occurs in this idealized state, the change in actual net interchange will be measuring only the decline in load due to lesser frequency and generator governor response, and, none of the contaminating influences. While the ACE may become negative due to the actual frequency response being less than that called for by the frequency bias setting within the BA’s AGC system, this contaminating influence on measuring frequency response will not appear in the actual net interchange value if the measurement interval ends before the generation on AGC responds.

Now let’s explore the sensitivity of the resultant frequency response sampling to the relaxation of these idealized circumstances.

1. The “60 Hz load” increases moderately due to time of day concurrent with the frequency event. If the frequency event happens before AGC or operator-directed manual load adjustments occur, then the actual net interchange will be reduced by the moderate increase in load and the frequency response will be underestimated. But if the frequency event happens while AGC response and/or manual adjustments occur, then the actual net interchange will be increased by the AGC response (and/or manual adjustments) and the frequency response will be overestimated.

2. The “60 Hz load” decreases moderately due to time of day concurrent with the frequency event. If the frequency event happens before AGC or operator-directed manual load adjustments occur, then the actual net interchange will be increased by the moderate reduction in load and the frequency response will be overestimated. But if the frequency event happens while AGC response and/or manual adjustments occur, then the actual net interchange will be decreased by the AGC response (and/or manual adjustments) and the frequency response will be underestimated.
3. In anticipation of increasing load during the next hour, the operator increases manual generation before the load actually appears. If the frequency event happens while the generation “leading” the load is increasing, then the actual net interchange will be increased by the increase in manual generation and the frequency response will be overestimated. But if the frequency event occurs when the result of AGC signals sent to offset the operator’s leading actions take effect, then the actual net interchange will be decreased and the frequency response is underestimated.
4. In anticipation of decreasing load during the next hour, the operator decreases manual generation before the load actually declines. If the frequency event happens while the generation “leading” the load downward is decreasing, then the actual net interchange will be decreased by the reduction in manual generation and the frequency response will be underestimated. But if the frequency event occurs when the result of AGC signals sent to offset the operator’s leading actions take effect, then the actual net interchange will be increased and the frequency response is overestimated.
5. A schedule change to export more energy is made at 5 minutes before the top of the hour. The BA’s “60 Hz load” is not changing. The schedule change is small enough that the operator is relying on upward movement of generators on AGC to provide the additional energy to be exported. The time at which the AGC generators actually begin to provide the additional energy is dependent on how much time passes before the AGC algorithm gets out of its deadbands, the individual generator control errors get large enough for sending out the control signal, and maybe 20 seconds to 3 minutes for the response to be effected. The key point here is that it is not clear when the effects of a schedule change, as manifested in a change in generation and then ultimately a change in actual net interchange, will occur.
6. With the expected penetration of wind in the near future, unanticipated changes in their output will tend to affect actual net interchange and add noise to the frequency response observation process.

To a greater or lesser extent, 1 through 4 above are happening continuously for the most part with most BAs in the Eastern and Western Interconnections. 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.

Proposed Resource Loss Protection Criteria

Background and Current Methodologies

The Resource Loss Protection Criteria (RLPC) is the respective Interconnection design resource loss in MW, which is used to determine the Interconnection Frequency Response Obligation (IFRO). An "N-2 Event" is defined as a single initiating event that leads to multiple (two or more) electrical facilities being removed from service. Examples of this are breaker failure events, bus faults, or double circuit tower outages.

Previously, the RLPC has been calculated from the largest N-2 events identified in each Interconnection, except for the Eastern Interconnection. In the Eastern Interconnection, the RLPC has been calculated using the largest single event in the previous ten years.

The RLPC value should be set for each Interconnection such that the underfrequency load shedding safety net is not activated for the largest N-2 Event. The previous BAL-003 IFRO methodology determined that the largest N-2 Event should not precipitate an underfrequency load shedding event. Ideally, the RLPC value should always equal or exceed the largest N-2 Event. If the RLPC is set to a larger value than the largest N-2 Event, the probability of an underfrequency load shedding event decreases. If the RLPC value is set to a value less than the largest N-2 Event, the probability of an underfrequency load shedding event increases.

A quantitative approach for selecting the RLPC can be implemented that minimizes the need for detailed system analysis to be performed annually.

Currently, each Balancing Authority (BA) or Reserve Sharing Group (RSG) determines its Most Severe Single Contingency (MSSC) with respect to resource loss as required by BAL-002-2(i), Requirement R2. The MSSC calculation is done in Real-time operations based on actual system configuration.

Relevant Definitions

For convenience, the definitions of the following terms defined in the Glossary of Terms used in NERC Reliability Standards are provided below. Where a conflict exists between the definition provided here and the definition in the Glossary, the definition in the Glossary shall control.

Most Severe Single Contingency:

The Balancing Contingency Event, due to a single contingency identified using system models maintained within the RSG or a BA's area that is not part of a RSG, that would result in the greatest loss (measured in Megawatts (MWs) of resource output used by the RSG or a BA that is not participating as a member of a RSG at the time of the event to meet Firm Demand and export obligation (excluding export obligation for which Contingency Reserve obligations are being met by the Sink Balancing Authority).

Balancing Contingency Event:
Any single event described in Subsections (A), (B), or (C) below, or any series of such otherwise single events, with each separated from the next by one minute or less.

A. Sudden loss of generation:
   a. Due to:
      i. unit tripping, or
      ii. loss of generator Facility resulting in isolation of the generator from the Bulk Electric System or from the responsible entity's System, or
      iii. sudden unplanned outage of transmission Facility.
   b. And that causes an unexpected change to the responsible entity's Area Control Error (ACE).
B. Sudden loss of an Import, due to forced outage of transmission equipment that causes an unexpected imbalance between generation and Demand on the Interconnection.
C. Sudden restoration of a Demand that was used as a resource that causes an unexpected change to the responsible entity's ACE.

Interconnection:
A geographic area in which the operation of Bulk Power System components is synchronized such that the failure of one or more of such components may adversely affect the ability of the operators of other components within the system to maintain Reliable Operation of the Facilities within their control. When capitalized, any one of the four major electric system networks in North America: Eastern, Western, ERCOT and Quebec.

Proposal
The Interconnection RLPC is calculated based on a resource loss in accordance with the following process:

NERC will request BAs to provide their two largest resource loss values and largest resource loss due to an N-1 or N-2 RAS event. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be needed to complete the calculation of the RLPC and IFRO.

BAs determine the two largest resource losses for the next operating year based on a review of the following items:

- The two largest independent Balancing Contingency Events, each due to a single contingency, identified using system models measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)
- The two largest units in the BA Area, regardless of shared ownership/responsibility.

- The two largest Remedial Action Scheme (RAS) resource losses (if any) which are initiated by single (N-1) contingency events.

The BA provides these two numbers determined above as Resource Loss A and Resource Loss B in the FRS Form 1.

The BA should then provide the largest resource loss due to RAS operations (if any) which is initiated by a multiple contingency (N-2) event (RLPC cannot be lower than this value). If the RAS impacts more than a single BA, one BA is asked to take the lead and sum all resources lost due to the RAS event and provide that information.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.

The host BA (or planned host BA) where jointly-owned resources are physically located, should be the only BA to report that resource. The full ratings of the resource, not the fractional shares, should be reported.

Direct-current (DC) ties to asynchronous resources (such as DC ties between Interconnections, or the Manitoba Hydro Dorsey bi-pole ties to their northern asynchronous generation) should be considered as resources losses. DC lines, such as the Pacific DC Intertie, which ties two sections of the same synchronous interconnection together, should not be reported. A single pole block with normal clearing in a monopole or bi-pole high-voltage direct current system is a single contingency.

For a hypothetical four-BA Interconnection, Plant 1, in BA1, has two generators rated at 1200 MW each. Plant 2, in BA2 has a generator rated at 1400 MW. BA2's next largest contingency is 1000 MW. The two largest resource losses for BA3 and BA4 are listed below.

BA1	Resource Loss A = 1200 MW	Resource Loss B = 1200 MW	Both at Plant 1 (N-2)
BA2	Resource Loss A= 1400 MW	Resource Loss B = 1000 MW	Electrically separate
BA3	Resource Loss A = 1000 MW	Resource Loss B = 800 MW	Electrically separate
BA4	Resource Loss A = 1500 MW (DC TIE)	Resource Loss B= 500 MW	Electrically separate

The ERO would apply the RLPC selection methodology described above to determine the RLPC for the Interconnection. Using this methodology, results in the following:

Largest Resource Loss = 1500 MW
Second Largest Resource Loss = 1400 MW
Summation of two largest resource losses = 2900 MW
Interconnection RLPC = 2900 MW

If only the N-2 Event was applied, the RLPC for the Interconnection would be 2400 MW. The summation of the two largest Interconnection Resource Losses will equal or exceed, but never fall short of, the N-2 Event scenario.

In order to evaluate RAS resource loss, single (N-1) and multiple (N-2) contingency events should be evaluated.

Hypothetically, in an Interconnection:

BA1 RAS = 2850 MW N-2 RAS event
BA1 Resource Loss A = 1150 MW
BA1 Resource Loss B = 800 MW
BA2 Resource Loss A = 1380 MW
BA2 Resource Loss B = 1380 MW
BA3 RAS = 1000 MW N-1 RAS event
BA3 Resource Loss A = 800 MW
BA3 Resource Loss B = 700 MW

In this case, the ERO would determine the RLPC as follows: the summation of the two largest resource losses is 2760 MW. Since the N-2 RAS event exceeds the summation of the two largest single contingency events, the RLPC is the N-2 RAS event, or 2850 MW.

Interconnection RLPC Values

Based on initial review, the numbers below would be representative of the RLPC for each Interconnection.

Eastern Interconnection:
Present RLPC = 4500 MW Load Credit = 0 MW
RESOURCE LOSS A = 1732 MW
RESOURCE LOSS B = 1477 MW
Proposed RLPC = 3209 MW

Western Interconnection:
Present RLPC = 2626 MW Load Credit = 0 MW
RESOURCE LOSS A = 1505 MW
RESOURCE LOSS B = 1344 MW
N-2 RAS = 2850 MW
Proposed RLPC = 2850 MW

ERCOT:
Present RLPC = 2750 MW Load Credit = 1209 MW
RESOURCE LOSS A = 1375 MW
RESOURCE LOSS B = 1375 MW
Proposed RLPC = 2750 MW

Quebec Interconnection:
Present RLPC = 1700 MW Load Credit = 0 MW
RESOURCE LOSS A = 1000 MW

RESOURCE LOSS B = 1000 MW
Proposed RLPC = 2000 MW

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Proposed Resource Loss Protection Criteria

Background and Current Methodologies

The Resource Loss Protection Criteria (RLPC) is the respective Interconnection design resource loss in MW, which is used to determine the Interconnection Frequency Response Obligation (IFRO).
An “N-2 Event” is defined as a single initiating event that leads to multiple (two or more) electrical facilities being removed from service. Examples of this are breaker failure events, bus faults, or double circuit tower outages.

Previously, the RLPC has been calculated from the largest N-2 events identified in each Interconnection, except for the Eastern Interconnection. In the Eastern Interconnection, the RLPC has been calculated using the largest single event in the previous ten years.

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BA3 Resource Loss A = 800 MW
BA3 Resource Loss B = 700 MW

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Proposed RLPC = 3209 MW

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Present RLPC = 2626 MW Load Credit = ~~120~~ 0 MW
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RESOURCE LOSS B = 1344 MW
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Present RLPC = 2750 MW Load Credit = 1209 MW
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RESOURCE LOSS B = 1375 MW
Proposed RLPC = 2750 MW

Quebec Interconnection:
Present RLPC = 1700 MW Load Credit = 0 MW
RESOURCE LOSS A = 1000 MW

RESOURCE LOSS B = 1000 MW
Proposed RLPC = 2000 MW

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Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

Version II - 2019

RELIABILITY | RESILIENCE | SECURITY

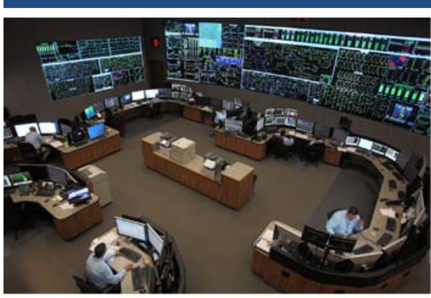


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Table of Contents

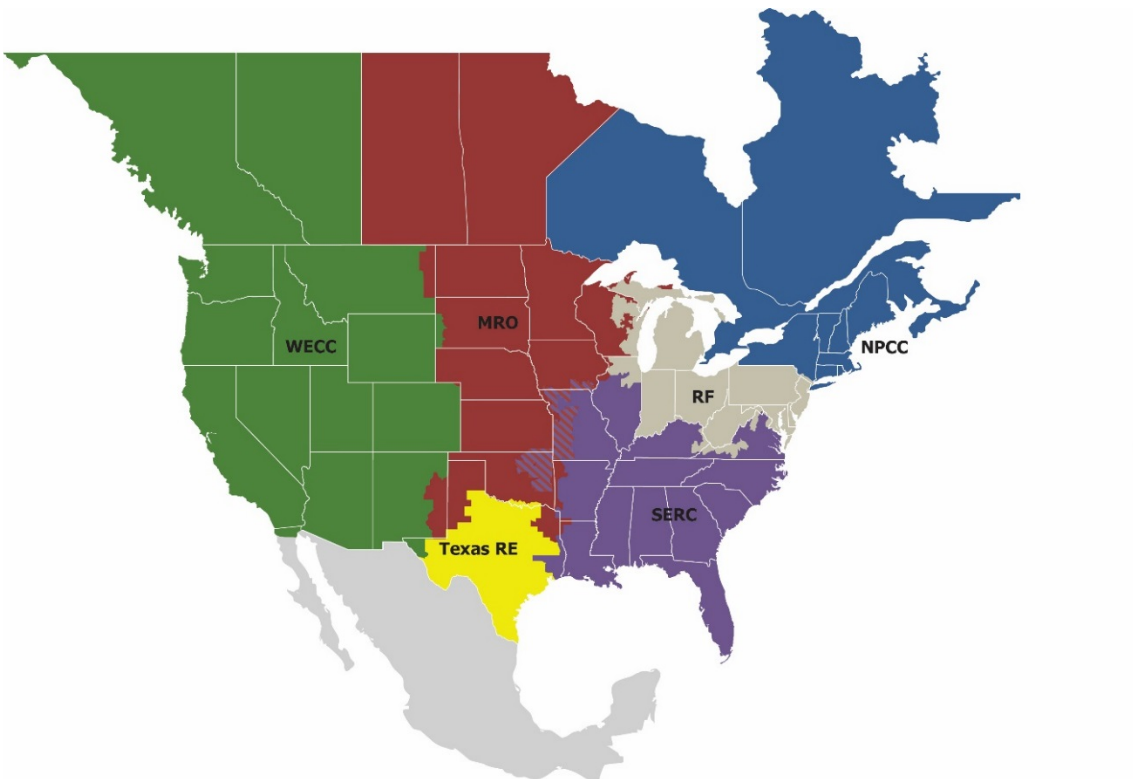
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

This procedure (Procedure) outlines the Electric Reliability Organization (ERO) process for supporting the Frequency Response Standard (FRS). A request for revisions may be submitted to the ERO or its designee for consideration. The request must provide a technical justification for the suggested modification. The ERO shall publicly post the suggested modification for a 45-day formal comment period and discuss the request in a public meeting. The ERO will make a recommendation to the NERC Board of Trustees (BOT), which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to this Procedure shall be filed with the Federal Energy Regulatory Commission (FERC) for informational purposes.

BAL-003-2 sets Interconnection Frequency Response Obligation (IFRO) to preset values subject to annual review. This procedure establishes the methods to be used for the annual review until Phase 2 of the SAR for Project 2017-01 has been addressed. If Frequency Response Measure (FRM) for the Eastern Interconnection degrades more than 10% in a year, the ERO will halt the reduction in IFRO until such time as a determination can be made as to the cause of the degradation.

Chapter 1: Event Selection Process

Event Selection Objectives

The goals of this procedure are to outline a transparent, repeatable process to annually identify a list of frequency events to be used to calculate Frequency Response to determine:

- Whether the Balancing Authority (BA) or Frequency Response Sharing Group (FRSG) met its Frequency Response Obligation, and
- An appropriate fixed Frequency Bias Setting.

Event Selection Criteria

1. The ERO will use the following criteria to select FRS excursion events for analysis. The events that best fit the criteria will be used to support the FRS. The evaluation period for performing the annual Frequency Bias Setting and the FRM calculation is December 1 of the prior year through November 30 of the current year.
2. The ERO will identify 20 to 35 frequency excursion events in each Interconnection for calculating the Frequency Bias Setting and the FRM. If the ERO cannot identify 20 frequency excursion events in a 12-month evaluation period satisfying the criteria below, then similar acceptable events from the previous year's evaluation period will be included with the data set by the ERO for determining compliance.
3. The ERO will use three criteria to determine if an acceptable frequency excursion event for the FRM has occurred:
    a. The change in frequency as defined by the difference from the A Value to Point C and the arrested frequency Point C exceeds the excursion threshold values specified for the Interconnection in Table 1 below.
        i. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline.
        ii. Point C is the arrested value of frequency observed within 20 seconds following the start of the excursion.

Table 1.1: Interconnection Frequency Excursion Threshold Values

Interconnection	A Value to Pt C	Point C (Low)	Point C (High)
East	0.04Hz	< 59.96	> 60.04
West	0.07Hz	< 59.95	> 60.05
ERCOT	0.08Hz	< 59.92	> 60.08
HQ	0.30Hz	< 59.85	> 60.15

    b. The time from the start of the rapid change in frequency until the point at which Frequency has stabilized within a narrow range should be less than 20 seconds.
    c. If any data point in the B Value average recovers to the A Value, the event will not be included.
4. Pre-disturbance frequency should be relatively steady and near 60.000 Hz for the A Value. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient

begins to decline. For example, given the choice of the two events below, the one on the right is preferred as the pre-disturbance frequency is stable and also closer to 60 Hz.

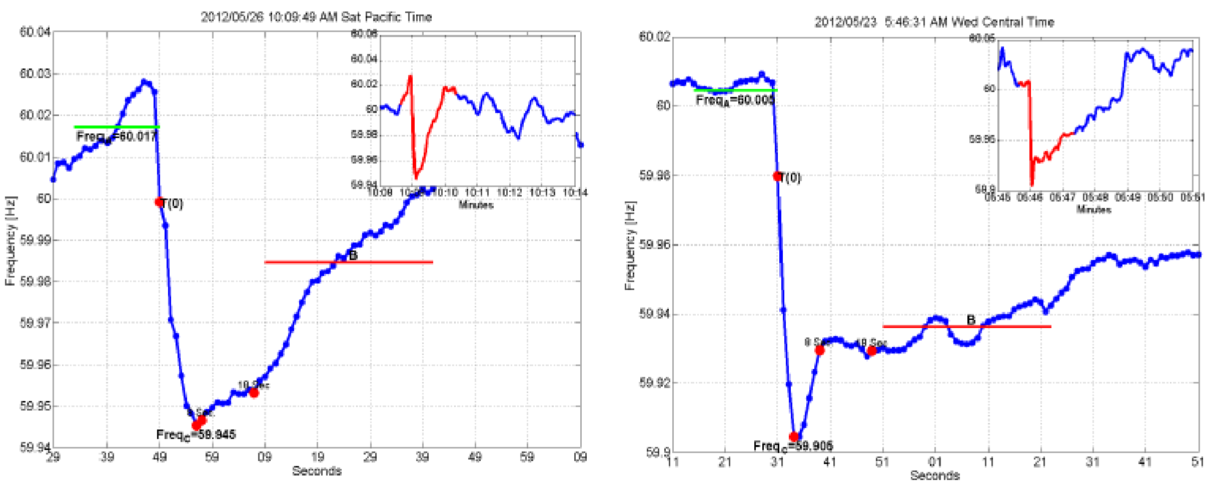


Figure 1.1: Pre-disturbance Frequency

5. Excursions that include 2 or more events that do not stabilize within 20 seconds will not be considered.
6. Frequency excursion events occurring during periods when large interchange schedule ramping or load change is happening, or within 5 minutes of the top of the hour may be excluded from consideration if other acceptable frequency excursion events from the same quarter are available.
7. The ERO will select the largest (A Value to Point C) 2 or 3 frequency excursion events occurring each month. If there are not 2 frequency excursion events satisfying the selection criteria in a month, then other frequency excursion events should be picked in the following sequence:
   a. From the same event quarter of the year.
   b. From an adjacent month.
   c. From a similar load season in the year (shoulder vs. summer/winter)
   d. The largest unused event.

As noted earlier, if a total of 20 events are not available in an evaluation year, then similar acceptable events from the next year's evaluation period will be included with the data set by the ERO for determining Frequency Response Obligation (FRO) compliance. The first year's small set of data will be reported and used for Bias Setting purposes, but compliance evaluation on the FRO will be done using a 24-month data set.

To assist Balancing Authority preparation for complying with this standard, the ERO will provide quarterly posting of candidate frequency excursion events for the current year FRM calculation. The ERO will post the final list of frequency excursion events used for standard compliance as specified in Attachment A of the standard. The following is a general description of the process that the ERO will use to ensure that BAs can evaluate events during the year in order to monitor their performance throughout the year.

Quarterly

The event lists will be reviewed quarterly, with the quarters defined as:

- December through February
- March through May
- June through August
- September through November

Based on criteria established in this Procedure, events will be selected to populate the FRS Form 1 for each Interconnection. The FRS Form 1's will be posted on the NERC website, in the Resources Subcommittee (RS) area under the title "Frequency Response Standard Resources". Updated FRS Form 1's will be posted at the end of each quarter listed above after a review by the NERC RS and its Frequency Working Group. While the events on this list are expected to be final, as outlined in the selection criteria, additional events may be considered, if the number of events throughout the year do not create a list of at least 20 events. It is intended that this quarterly posting of updates to the FRS Form 1 would allow BAs to evaluate the events throughout the year, lessening the burden when the yearly posting is made.

Annually

The final FRS Form 1 for each Interconnection, which would contain the events from all four quarters listed above, will be posted as specified in Attachment A. Each BA reports its previous year's Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO as specified in Attachment A using the final FRS Form 1. The ERO will check for errors and use the FRS Form 1 data to calculate CPS limits and FROs for the upcoming year.

Once the data listed above is fully reviewed, the ERO may adjust the implementation specified in Attachment A for changing the Frequency Bias Settings and CPS limits. This allows flexibility when each BA implements its settings.

Chapter 2: Process for Adjusting Interconnection Minimum Frequency Bias Setting

This procedure outlines the process the ERO is to use for modifying minimum Frequency Bias Settings to better meet reliability needs. The ERO will adjust the Frequency Bias Setting minimum in accordance with this procedure.
The ERO will post the minimum Frequency Bias Setting values on the ERO website along with other balancing standard limits.

Under BAL-003-2, the minimum Frequency Bias Settings will be moved toward the natural Frequency Response in each Interconnection. In the first year, the minimum Frequency Bias Setting for each Interconnection is shown in Table 2 below. Each Interconnection Minimum Frequency Bias Setting is based on the sum of the non-coincident peak loads for each BA from the currently available FERC 714 Report or equivalent. This non-coincident peak load sum is multiplied by the percentage shown in Table 2 to get the Interconnection Minimum Frequency Bias Setting. The Interconnection Minimum Frequency Bias Setting is allocated among the BAs on an Interconnection using the same allocation method as is used for the allocation of the Frequency Response Obligation (FRO).

Table 2.1: Frequency Bias Setting Minimums

Interconnection	Interconnection Minimum Frequency Bias Setting (in MW/0.1Hz)
Eastern	0.9% of non-coincident peak load
Western	0.9% of non-coincident peak load
ERCOT	N/A
HQ	N/A

*The minimum Frequency Bias Setting requirement does not apply to a Balancing Authority that is the only Balancing Authority in its Interconnection. These Balancing Authorities are solely responsible for providing reliable frequency control of their Interconnection. These BAs are responsible for converting frequency error into a megawatt error to provide reliable frequency control, and the imposition of a minimum bias setting greater than the magnitude the Frequency Response Obligation may have the potential to cause control system hunting, and instability in the extreme.

The ERO, in coordination with the regions of each Interconnection, will annually review Frequency Bias Setting data submitted by BAs. 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 peak load (expressed in MW/0.1Hz), the minimum Frequency Bias Setting for BAs within that Interconnection may be reduced (in absolute value) in the subsequent years FRS Form 1 based on the technical evaluation and consultation with the regions affected by 0.1 percentage point of peak load (expressed in MW/0.1Hz) to better match that Frequency Bias Setting and natural Frequency Response.

The ERO, in coordination with the regions of each Interconnection, will monitor the impact of the reduction of minimum frequency bias settings, if any, on frequency performance, control performance, and system reliability. If unexpected and undesirable impacts such as, but not limited to, sluggish post-contingency restoration of frequency to schedule or control performance problems occur, then the prior reduction in the minimum frequency bias settings may be reversed, and/or the prospective reduction based on the criterion stated above may not be implemented.

Chapter 3: Interconnection Frequency Response Obligation Methodology

The Interconnection Resource Loss Protection Criteria (RLPC) is calculated based a resource loss in accordance with the following process:

NERC will request BAs to provide their two largest resource loss values and largest resource loss due to an N-1 or N-2 RAS event. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be needed to complete the calculation of the RLPC and IFRO.

BAs determine the two largest resource losses for the next operating year based on a review of the following items:

- The two largest independent Balancing Contingency Events, each due to a single contingency, identified using system models measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)
- The two largest units in the BA Area, regardless of shared ownership/responsibility.
- The two largest Remedial Action Scheme (RAS) resource losses (if any) which are initiated by single (N-1) contingency events.

The BA provides these two numbers determined above as Resource Loss A and Resource Loss B in the FR Form 1.

The BA should then provide the largest resource loss due to RAS operations (if any) which is initiated by a multiple contingency (N-2) event (RLPC cannot be lower than this value). If this RAS impacts more than a single BA, one BA is asked to take the lead and sum all resources lost due to the RAS event and provide that information.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.

The host BA (or planned host BA) where jointly-owned resources are physically located, should be the only BA to report that resource. The full ratings of the resource, not the fractional shares, should be reported.

Direct-current (DC) ties to asynchronous resources (such as DC ties between Interconnections, or the Manitoba Hydro Dorsey bi-pole ties to their northern asynchronous generation) should be considered as resource losses. DC lines such as the Pacific DC Intertie, which ties two sections of the same synchronous Interconnection together, should not be reported. A single pole block with normal clearing in a monopole or bi-pole high-voltage direct current system is a single contingency.

For a hypothetical four-BA Interconnection, Plant 1, in BA1, has two generators rated at 1200 MW each. Plant 2, in BA2 has a generator rated at 1400 MW. BA2's next largest contingency is 1000 MW. The two largest resource losses for BA3 and BA4 are listed below.

BA1	Resource Loss A = 1200 MW	Resource Loss B = 1200 MW	Both at Plant 1 (N-2)
BA2	Resource Loss A= 1400 MW	Resource Loss B = 1000 MW	Electrically separate
BA3	Resource Loss A = 1000 MW	Resource Loss B = 800 MW	Electrically separate
BA4	Resource Loss A = 1500 MW (DC TIE)	Resource Loss B = 500 MW	Electrically separate

The ERO would apply the RLPC selection methodology described above to determine the RLPC for the Interconnection. Using this methodology, results in the following:

Largest Resource Loss = 1500 MW
Second Largest Resource Loss = 1400 MW
Summation of two largest resource losses = 2900 MW
Interconnection RLPC = 2900 MW

If only the N-2 Event was applied, the RLPC for the Interconnection would be 2400 MW. The summation of the two largest Interconnection Resource Losses will equal or exceed, but never fall short of, the N-2 Event scenario.

In order to evaluate RAS resource loss, single (N-1) and multiple (N-2) contingency events should be evaluated. Hypothetically, in an Interconnection:

BA1 RAS = 2850 MW N-2 RAS event
BA1 Resource Loss A = 1150 MW
BA1 Resource Loss B = 800 MW
BA2 Resource Loss A = 1380 MW
BA2 Resource Loss B = 1380 MW
BA3 RAS = 1000 MW N-1 RAS event
BA3 Resource Loss A = 800 MW
BA3 Resource Loss B = 700 MW

In this case, the ERO would determine the RLPC as follows: the summation of the two largest resource losses is 2760 MW. Since the N-2 RAS event exceeds the summation of the two largest single contingency events, the RLPC is the N-2 RAS event, or 2850 MW.

Interconnection RLPC Values

Based on initial review, the numbers below would be representative of the RLPC for each Interconnection.

Eastern Interconnection:
Present RLPC = 4500 MW Load Credit = 0 MW
RESOURCE LOSS A = 1732 MW
RESOURCE LOSS B = 1477 MW
Proposed RLPC = 3209 MW

Western Interconnection:
Present RLPC = 2626 MW Load Credit = 0 MW
RESOURCE LOSS A = 1505 MW
RESOURCE LOSS B = 1344 MW
N-2 RAS = 2850 MW
Proposed RLPC = 2850 MW

ERCOT:
Present RLPC = 2750 MW Load Credit = 1209 MW
RESOURCE LOSS A = 1375 MW
RESOURCE LOSS B = 1375 MW
Proposed RLPC = 2750 MW

Quebec Interconnection:
Present RLPC = 1700 MW Load Credit = 0 MW
RESOURCE LOSS A = 1000 MW
RESOURCE LOSS B = 1000 MW
Proposed RLPC = 2000 MW

Calculation of IFRO Values

The IFRO is calculated using the RLPC (reference is from Table 1 from BAL-003-2):

$$IFRO = \frac{(RLPC-CLR)}{(MDF*10)} \quad \text{expressed as MW/0.1Hz}$$

MDF is the Maximum Delta Frequency for the specific interconnection as determined in the 2017 Frequency Response Annual Analysis (FRAA).

Interconnection Frequency Response Obligation

Interconnection	**Eastern**	**Western**	**ERCOT**	**HQ**	**Units**
Max. Delta Frequency (MDF)	**0.420**	**0.280**	**0.405**	**0.947**	Hz
Resource Loss Protection Criteria (RLPC)	**3,209**	**2,850**	**2,750**	**2,000**	MW
Credit for Load Resources (CLR)			**1,209**		MW
Calculated IFRO	**-784***	**-1018**	**-380**	**-211**	MW/0.1Hz

* Eastern Interconnection IFRO will be stepped down to this level over three years per BAL-003-2.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

Version II – 2019

RELIABILITY | RESILIENCE | SECURITY

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Atlanta, GA 30326
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Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

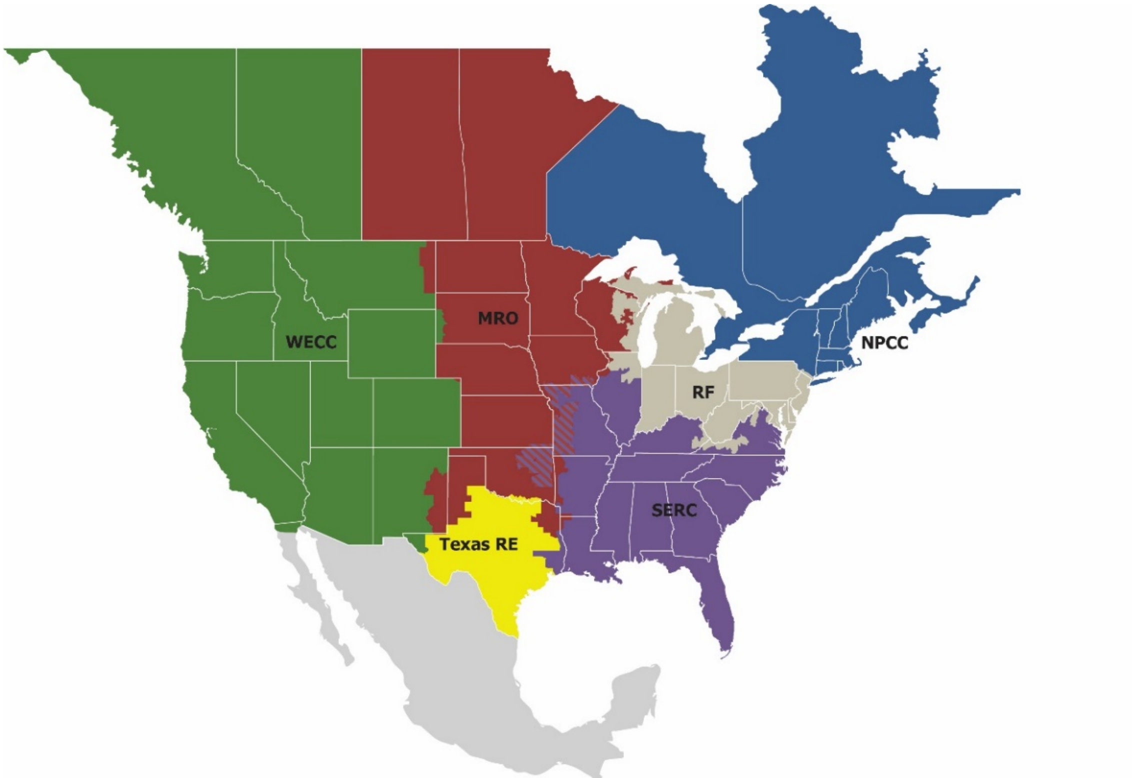
Reliability | Resilience | Security

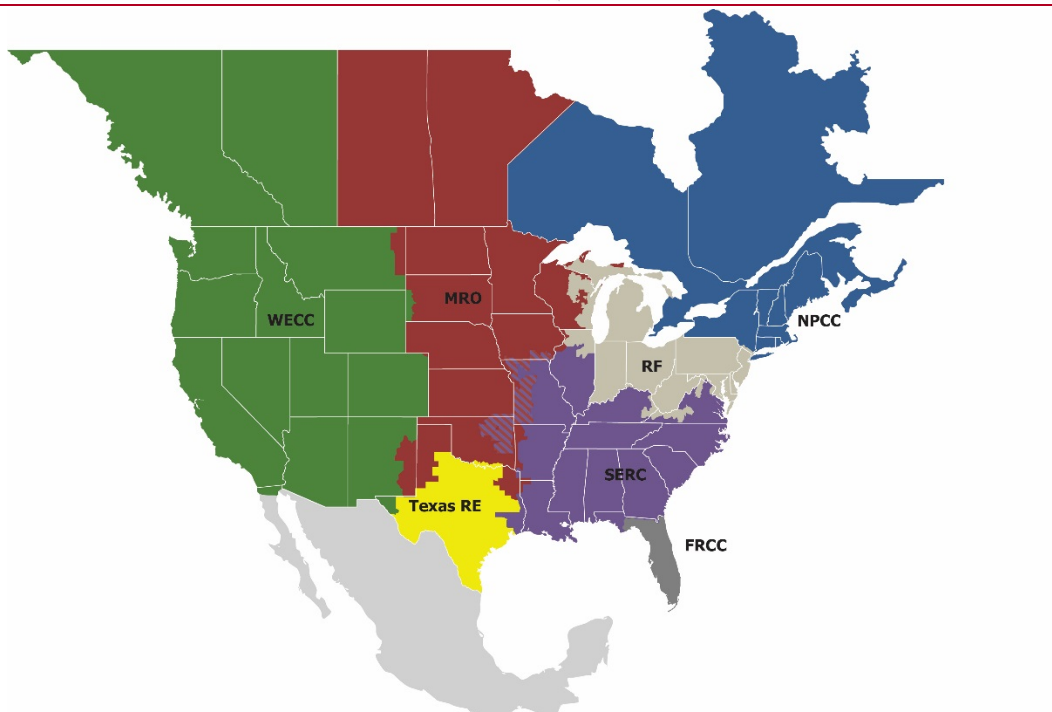
Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.

~~The vision for the Electric Reliability Organization (ERO) Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the seven Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.~~

~~The North American BPS is divided into seven RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.~~





MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity

WECC	Western Electricity Coordinating Council

~~**FRCC**~~	~~Florida Reliability Coordinating Council~~
~~**MRO**~~	~~Midwest Reliability Organization~~
~~**NPCC**~~	~~Northeast Power Coordinating Council~~
~~**RF**~~	~~ReliabilityFirst~~
~~**SERC**~~	~~SERC Reliability Corporation~~
~~**Texas RE**~~	~~Texas Reliability Entity~~
~~**WECC**~~	~~Western Electricity Coordinating Council~~

Introduction

This procedure (Procedure) outlines the Electric Reliability Organization (ERO) process for supporting the Frequency Response Standard (FRS). A request for revisions may be submitted to the ~~Operating Committee (OC) of the~~ ERO or its designee for consideration. The request must provide a technical justification for the suggested modification. The ERO shall publicly post the suggested modification for a 45-day formal comment period and discuss the request in a public meeting~~ of the ERO OC~~. ~~-~~The ERO will make a recommendation to the NERC Board of Trustees (BOT), which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to this Procedure shall be filed with the Federal Energy Regulatory Commission (FERC) for informational purposes.

BAL-003-2 sets Interconnection Frequency Response Obligation (IFRO) to preset values subject to annual review. This procedure establishes the methods to be used for the annual review until Phase 2 of the SAR for Project 2017-01 has been addressed. If Frequency Response Measure (FRM) for the Eastern Interconnection degrades more than 10% in a year, the ERO will halt the reduction in IFRO until such time as a determination can be made as to the cause of the degradation.

Chapter 1: Event Selection Process

Event Selection Objectives

The goals of this procedure are to outline a transparent, repeatable process to annually identify a list of frequency events to be used to calculate Frequency Response to determine:

- Whether the Balancing Authority (BA) or Frequency Response Sharing Group (FRSG) met its Frequency Response Obligation, and
- An appropriate fixed Frequency Bias Setting.

Event Selection Criteria

1. The ERO will use the following criteria to select FRS excursion events for analysis. The events that best fit the criteria will be used to support the FRS. The evaluation period for performing the annual Frequency Bias Setting and the FRM calculation is December 1 of the prior year through November 30 of the current year.
2. The ERO will identify 20 to 35 frequency excursion events in each Interconnection for calculating the Frequency Bias Setting and the FRM. If the ERO cannot identify 20 frequency excursion events in a 12-month evaluation period satisfying the criteria below, then similar acceptable events from the ~~subsequent~~ previous year's evaluation period will be included with the data set by the ERO for determining compliance.
3. The ERO will use three criteria to determine if an acceptable frequency excursion event for the FRM has occurred:
   a. The change in frequency as defined by the difference from the A Value to Point C and the arrested frequency Point C exceeds the excursion threshold values specified for the Interconnection in Table 1 below.
      i. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline.
      ii. Point C is the arrested value of frequency observed within 20 seconds following the start of the excursion.

Table 1.1: Interconnection Frequency Excursion Threshold Values

Interconnection	A Value to Pt C	Point C (Low)	Point C (High)
East	0.04Hz	< 59.96	> 60.04
West	0.07Hz	< 59.95	> 60.05
ERCOT	0.08~~15~~Hz	< 59.~~90~~92	> 60.08~~10~~
HQ	0.30Hz	< 59.85	> 60.15

   b. The time from the start of the rapid change in frequency until the point at which Frequency has stabilized within a narrow range should be less than ~~18~~ 20 seconds.
   c. If any data point in the B Value average recovers to the A Value, the event will not be included.
4. Pre-disturbance frequency should be relatively steady and near 60.000 Hz for the A Value. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient

begins to decline. For example, given the choice of the two events below, the one on the right is preferred as the pre-disturbance frequency is stable and also closer to 60 Hz.

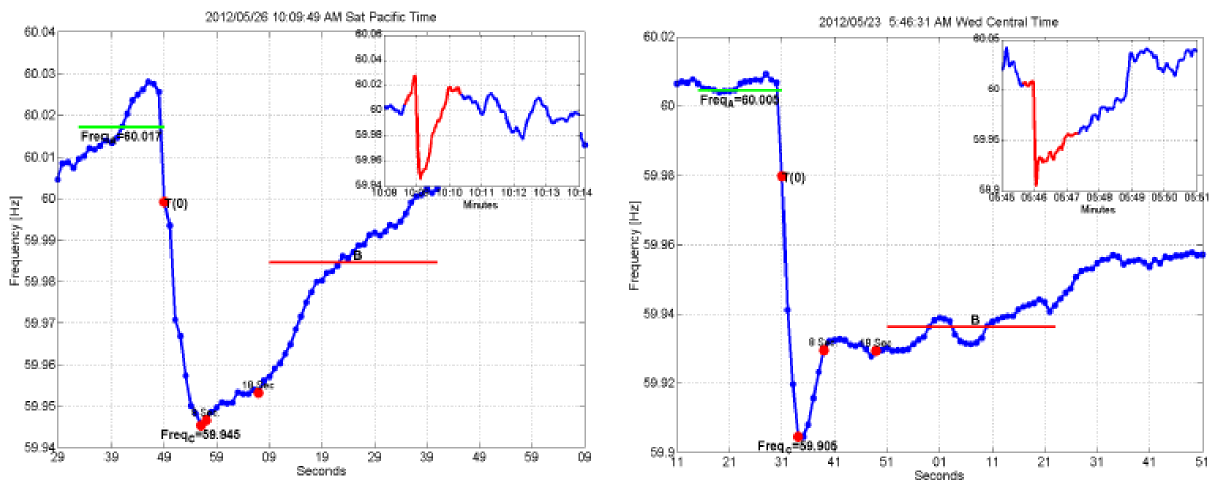


Figure 1.1: Pre-disturbance Frequency

5. Excursions that include 2 or more events that do not stabilize within ~~18~~ 20 seconds will not be considered.
6. Frequency excursion events occurring during periods~~:~~ when large interchange schedule ramping or load change is happening, or within 5 minutes of the top of the hour may be excluded from consideration if other acceptable frequency excursion events from the same quarter are available.

   ~~a. when large interchange schedule ramping or load change is happening, or~~

   ~~within 5 minutes of the top of the hour, will be excluded from consideration if other acceptable frequency excursion events from the same quarter are available.~~

7. The ERO will select the largest (A Value to Point C) 2 or 3 frequency excursion events occurring each month. If there are not 2 frequency excursion events satisfying the selection criteria in a month, then other frequency excursion events should be picked in the following sequence:
   a. From the same event quarter of the year.
   b. From an adjacent month.
   c. From a similar load season in the year (shoulder vs. summer/winter)
   d. The largest unused event.

As noted earlier, if a total of 20 events are not available in an evaluation year, then similar acceptable events from the next year's evaluation period will be included with the data set by the ERO for determining Frequency Response Obligation (FRO) compliance. The first year's small set of data will be reported and used for Bias Setting purposes, but compliance evaluation on the FRO will be done using a 24-month data set.

To assist Balancing Authority preparation for complying with this standard, the ERO will provide quarterly posting of candidate frequency excursion events for the current year FRM calculation. The ERO will post the final list of frequency excursion events used for standard compliance as specified in Attachment A of the standard. The following is a general description of the process that the ERO will use to ensure that BAs can evaluate events during the year in order to monitor their performance throughout the year.

Quarterly

The event lists will be reviewed quarterly, with the quarters defined as:

- December through February
- March through May
- June through August
- September through November

Based on criteria established in this Procedure, events will be selected to populate the FRS Form 1 for each Interconnection. The FRS Form 1's will be posted on the NERC website, in the Resources Subcommittee (RS) area under the title "Frequency Response Standard Resources". Updated FRS Form 1's will be posted at the end of each quarter listed above after a review by the NERC ~~Resources Subcommittee (~~RS~~)~~ and its Frequency Working Group. While the events on this list are expected to be final, as outlined in the selection criteria, additional events may be considered, if the number of events throughout the year do not create a list of at least 20 events. It is intended that this quarterly posting of updates to the FRS Form 1 would allow BAs to evaluate the events throughout the year, lessening the burden when the yearly posting is made.

Annually

The final FRS Form 1 for each Interconnection, which would contain the events from all four quarters listed above, will be posted as specified in Attachment A. Each ~~Balancing Authority~~BA reports its previous year's Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO as specified in Attachment A using the final FRS Form 1. The ERO will check for errors and use the FRS Form 1 data to calculate CPS limits and FROs for the upcoming year.

Once the data listed above is fully reviewed, the ERO may adjust the implementation specified in Attachment A for changing the Frequency Bias Settings and CPS limits. This allows flexibility when each BA implements its settings.

Chapter 2: Process for Adjusting Interconnection Minimum Frequency Bias Setting

This procedure outlines the process the ERO is to use for modifying minimum Frequency Bias Settings to better meet reliability needs. The ERO will adjust the Frequency Bias Setting minimum in accordance with this procedure.
The ERO will post the minimum Frequency Bias Setting values on the ERO website along with other balancing standard limits.

Under BAL-003-2, the minimum Frequency Bias Settings will be moved toward the natural Frequency Response in each Interconnection. In the first year, the minimum Frequency Bias Setting for each Interconnection is shown in Table 2 below. Each Interconnection Minimum Frequency Bias Setting is based on the sum of the non-coincident peak loads for each BA from the currently available FERC 714 Report or equivalent. This non-coincident peak load sum is multiplied by the percentage shown in Table 2 to get the Interconnection Minimum Frequency Bias Setting. The Interconnection Minimum Frequency Bias Setting is allocated among the BAs on an Interconnection using the same allocation method as is used for the allocation of the Frequency Response Obligation (FRO).

Table 2.1: Frequency Bias Setting Minimums

Interconnection	Interconnection Minimum Frequency Bias Setting (in MW/0.1Hz)
Eastern	0.9% of non-coincident peak load
Western	0.9% of non-coincident peak load
ERCOT	N/A
HQ	N/A

*The minimum Frequency Bias Setting requirement does not apply to a Balancing Authority that is the only Balancing Authority in its Interconnection. These Balancing Authorities are solely responsible for providing reliable frequency control of their Interconnection. These ~~Balancing Authorities~~BAs are responsible for converting frequency error into a megawatt error to provide reliable frequency control, and the imposition of a minimum bias setting greater than the magnitude the Frequency Response Obligation may have the potential to cause control system hunting, and instability in the extreme.

The ERO, in coordination with the regions of each Interconnection, will annually review Frequency Bias Setting data submitted by BAs. 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 peak load (expressed in MW/0.1Hz), the minimum Frequency Bias Setting for BAs within that Interconnection may be reduced (in absolute value) in the subsequent years FRS Form 1 based on the technical evaluation and consultation with the regions affected by 0.1 percentage point of peak load (expressed in MW/0.1Hz) to better match that Frequency Bias Setting and natural Frequency Response.

The ERO, in coordination with the regions of each Interconnection, will monitor the impact of the reduction of minimum frequency bias settings, if any, on frequency performance, control performance, and system reliability. ~~ ~~If unexpected and undesirable impacts such as, but not limited to, sluggish post-contingency restoration of frequency to schedule or control performance problems occur, then the prior reduction in the minimum frequency bias settings may be reversed, and/or the prospective reduction based on the criterion stated above may not be implemented.

Chapter 3: Interconnection Frequency Response Obligation Methodology

The Interconnection Resource Loss Protection Criteria (RLPC) is calculated based a resource loss in accordance with the following process:

NERC will request BAs to provide their two largest resource loss values and largest resource loss due to an N-1 or N-2 RAS event~~ – or largest resource as described above~~. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be needed to complete the calculation of the RLPC and IFRO.

BAs determine the two largest resource losses for the next operating year based on a review of the following items:

- The two largest independent Balancing Contingency Events, each due to a single contingency, identified using system models ~~in terms of loss~~ measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)
- The two largest units in the BA Area, regardless of shared ownership/responsibility.
- The two largest Remedial Action Scheme (RAS) resource losses (if any) which are initiated by single (N-1) contingency events.

The BA provides these two numbers determined above as Resource Loss A and Resource Loss B in the FR Form 1.

The BA should then provide the largest resource loss due to RAS operations (if any) which is initiated by a multiple contingency (N-2) event (RLPC cannot be lower than this value). If this RAS impacts more than a single BA, one BA is asked to take the lead and sum all resources lost due to the RAS event and provide that information.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.

The host BA (or planned host BA) where jointly-owned resources are physically located, should be the only BA to report that resource. The full ratings of the resource, not the fractional shares, should be reported.

Direct-current (DC) ties to asynchronous resources (such as DC ties between Interconnections, or the Manitoba Hydro Dorsey bi-pole ties to their northern asynchronous generation) should be considered as resource losses. DC lines such as the Pacific DC Intertie, which ties two sections of the same synchronous Interconnection together, should not be reported. A single pole block with normal clearing in a monopole or bi-pole high-voltage direct current system is a single contingency.

For a hypothetical four-BA Interconnection, Plant 1, in BA1, has two generators rated at 1200 MW each. Plant 2, in BA2 has a generator rated at 1400 MW. BA2's next largest contingency is 1000 MW. The two largest resource losses for BA3 and BA4 are listed below.

BA1	Resource Loss A = 1200 MW	Resource Loss B = 1200 MW	Both at Plant 1 (N-2)
BA2	Resource Loss A= 1400 MW	Resource Loss B = 1000 MW	Electrically separate
BA3	Resource Loss A = 1000 MW	Resource Loss B = 800 MW	Electrically separate
BA4	Resource Loss A = 1500 MW (DC TIE)	Resource Loss B = 500 MW	Electrically separate

The ERO would apply the RLPC selection methodology described above to determine the RLPC for the Interconnection. Using this methodology, results in the following:

Largest Resource Loss = 1500 MW
Second Largest Resource Loss = 1400 MW
Summation of two largest resource losses = 2900 MW
Interconnection RLPC = 2900 MW

If only the N-2 Event was applied, the RLPC for the Interconnection would be 2400 MW. The summation of the two largest Interconnection Resource Losses will equal or exceed, but never fall short of, the N-2 Event scenario.

In order to evaluate RAS resource loss, single (N-1) and multiple (N-2) contingency events should be evaluated.

Hypothetically, in an Interconnection:

BA1 RAS = 2850 MW N-2 RAS event
BA1 Resource Loss A = 1150 MW
BA1 Resource Loss B = 800 MW
BA2 Resource Loss A = 1380 MW
BA2 Resource Loss B = 1380 MW
BA3 RAS = 1000 MW N-1 RAS event
BA3 Resource Loss A = 800 MW
BA3 Resource Loss B = 700 MW

In this case, the ERO would determine the RLPC as follows: the summation of the two largest resource losses is 2760 MW. Since the N-2 RAS event exceeds the summation of the two largest single contingency events, the RLPC is the N-2 RAS event, or 2850 MW.

Interconnection RLPC Values

Based on initial review, the numbers below would be representative of the RLPC for each Interconnection.

Eastern Interconnection:
Present RLPC = 4500 MW Load Credit = 0 MW
RESOURCE LOSS A = 1732 MW
RESOURCE LOSS B = 1477 MW
Proposed RLPC = 3209 MW

Western Interconnection:
Present RLPC = 2626 MW Load Credit = ~~120~~ 0 MW
RESOURCE LOSS A = 1505 MW
RESOURCE LOSS B = 1344 MW
N-2 RAS = 2850 MW
Proposed RLPC = 2850 MW

ERCOT:
Present RLPC = 2750 MW Load Credit = 1209 MW
RESOURCE LOSS A = 1375 MW
RESOURCE LOSS B = 1375 MW

Proposed RLPC = 2750 MW

Quebec Interconnection:
Present RLPC = 1700 MW Load Credit = 0 MW
RESOURCE LOSS A = 1000 MW
RESOURCE LOSS B = 1000 MW
Proposed RLPC = 2000 MW

Calculation of IFRO Values

The IFRO is calculated using the RLPC (reference is from Table 1 from BAL-003-2):

$$IFRO = \frac{(RLPC-CLR)}{(MDF*10)} \quad \text{expressed as MW/0.1Hz}$$

MDF is the Maximum Delta Frequency for the specific interconnection as determined in the 2017 Frequency Response Annual Analysis (FRAA).

Interconnection Frequency Response Obligation

Interconnection	**Eastern**	**Western**	**ERCOT**	**HQ**	**Units**
Max. Delta Frequency (MDF)	**0.420**	**0.280**	**0.405**	**0.947**	Hz
Resource Loss Protection Criteria (RLPC)	**3,209**	**2,850**	**2,750**	**2,000**	MW
Credit for Load Resources (CLR)			**1,209**		MW
Calculated IFRO	**-~~764~~784***	**-1018**	**-380~~1~~**	**-211**	MW/0.1Hz

* Eastern Interconnection IFRO will be stepped down to this level over three years per BAL-003-2.

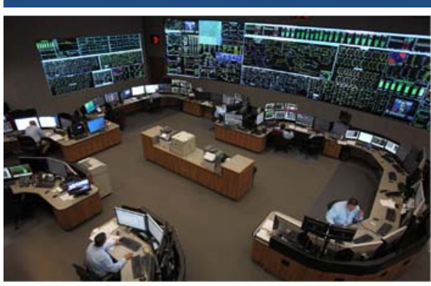
NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard

Version II - 2019

RELIABILITY | RESILIENCE | SECURITY




3353 Peachtree Road NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Table of Contents

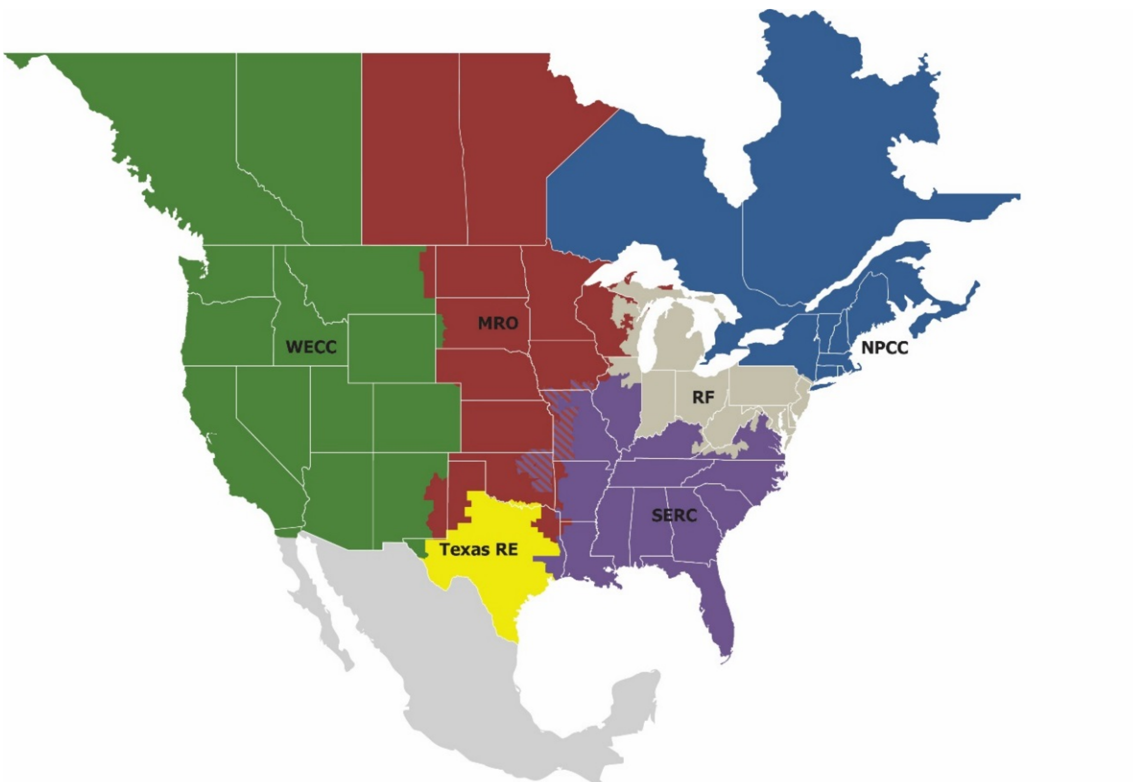
Preface

Electricity is a key component of the fabric of modern society and the Electric Reliability Organization (ERO) Enterprise serves to strengthen that fabric. The vision for the ERO Enterprise, which is comprised of the North American Electric Reliability Corporation (NERC) and the six Regional Entities (REs), is a highly reliable and secure North American bulk power system (BPS). Our mission is to assure the effective and efficient reduction of risks to the reliability and security of the grid.

Reliability | Resilience | Security

Because nearly 400 million citizens in North America are counting on us

The North American BPS is divided into six RE boundaries as shown in the map and corresponding table below. The multicolored area denotes overlap as some load-serving entities participate in one Region while associated Transmission Owners/Operators participate in another.



MRO	Midwest Reliability Organization
NPCC	Northeast Power Coordinating Council
RF	ReliabilityFirst
SERC	SERC Reliability Corporation
Texas RE	Texas Reliability Entity
WECC	Western Electricity Coordinating Council

Introduction

This procedure outlines the Electric Reliability Organization (ERO) process for supporting the Frequency Response Standard (FRS). A ~~Procedure revision~~ request for revisions may be submitted to the ERO or its designee for consideration. The ~~revision~~ request must provide a technical justification for the suggested modification. The ERO shall publicly post the suggested modification for a 45-day formal comment period and discuss the ~~revision~~ request in a public meeting. The ERO will make a recommendation to the NERC Board of Trustees (BOT), which may adopt the revision request, reject it, or adopt it with modifications. Any approved revision to this Procedure shall be filed with the Federal Energy Regulatory Commission (FERC) for informational purposes.

BAL-003-2 sets Interconnection Frequency Response Obligation (IFRO) to preset values subject to annual review. This procedure establishes the methods to be used for the annual review until Phase 2 of the SAR for Project 2017-01 has been addressed. If Frequency Response Measure (FRM) for the Eastern Interconnection degrades more than 10% in a year, the ERO will halt the reduction in IFRO until such time as a determination can be made as to the cause of the degradation.

Chapter 1: Event Selection Process

Event Selection Objectives

The goals of this procedure are to outline a transparent, repeatable process to annually identify a list of frequency events to be used ~~by Balancing Authorities (BA)~~ to calculate their Frequency Response to determine:

- Whether the ~~BA~~ Balancing Authority or Frequency Response Sharing Group (FRSG) met its Frequency Response Obligation, and
- An appropriate fixed Frequency Bias Setting.

Event Selection Criteria

1. The ERO will use the following criteria to select FRS ~~frequency~~ excursion events for analysis. The events that best fit the criteria will be used to support the FRS. ~~-~~The evaluation period for performing the annual Frequency Bias Setting and the ~~Frequency Response Measure (FRM)~~FRM calculation is December 1 of the prior year through November 30 of the current year.
2. The ERO will identify 20 to 35 frequency excursion events in each Interconnection for calculating the Frequency Bias Setting and the FRM. ~~-~~If the ERO cannot identify 20 frequency excursion events in a 12 month evaluation period satisfying the criteria below, then similar acceptable events from the ~~subsequent~~ previous year's evaluation period will be included with the data set by the ERO for determining ~~FRS~~ compliance. ~~This is described later.~~
3. The ERO will use three criteria to determine if an acceptable frequency excursion event for the FRM has occurred:
   a. The change in frequency as defined by the difference from the A Value to Point C and the arrested frequency Point C exceeds the excursion threshold values specified for the Interconnection in Table 1 below.
      i. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline.
      ii. Point C is the arrested value of frequency observed within ~~12~~ 20 seconds following the start of the excursion.

Table 1.1: Interconnection Frequency Excursion Threshold Values			
Interconnection	**A Value to Pt C**	**Point C (Low)**	**Point C (High)**
East	0.04Hz	< 59.96	> 60.04
West	0.07Hz	< 59.95	> 60.05
ERCOT	0.~~15Hz~~08Hz	< 59.~~90~~92	> 60.~~10~~08
HQ	0.30Hz	< 59.85	> 60.15

   b. The time from the start of the rapid change in frequency until the point at which Frequency has stabilized within a narrow range should be less than ~~18~~ 20 seconds.
   c. If any data point in the B Value average recovers to the A Value, the event will not be included.

4. Pre-disturbance frequency should be relatively steady and near 60.000 Hz for the A Value. The A Value is computed as an average over the period from -16 seconds to 0 seconds before the frequency transient begins to decline. For example, given the choice of the two events below, the one on the right is preferred as the pre-disturbance frequency is stable and also closer to 60 Hz.

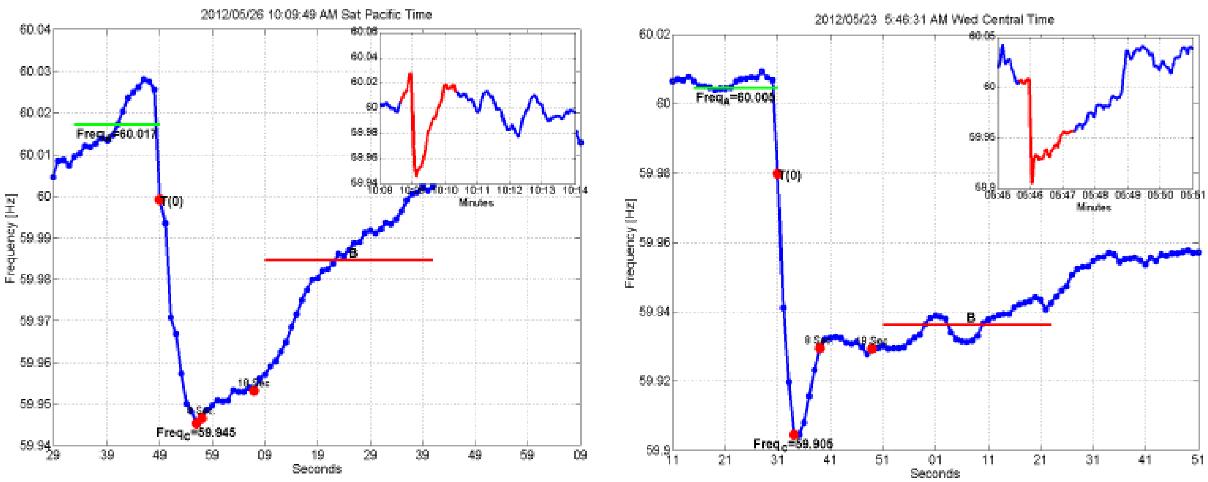


Figure 1.1: Pre-disturbance Frequency

5. Excursions that include 2 or more events that do not stabilize within ~~18~~ 20 seconds will not be considered.

6. Frequency excursion events occurring during periods~~:~~ when large interchange schedule ramping or load change is happening, or within 5 minutes of the top of the hour may be excluded from consideration if other acceptable frequency excursion events from the same quarter are available.

   ~~. when large interchange schedule ramping or load change is happening, or~~

   ~~. within 5 minutes of the top of the hour, will be excluded from consideration if other acceptable frequency excursion events from the same quarter are available.~~

~~9.~~7. The ERO will select the largest (A Value to Point C) 2 or 3 frequency excursion events occurring each month. If there are not 2 frequency excursion events satisfying the selection criteria in a month, then other frequency excursion events should be picked in the following sequence:

   a. From the same event quarter of the year.

   b. From an adjacent month.

   c. From a similar load season in the year (shoulder vs. summer/winter)

   d. The largest unused event.

As noted earlier, if a total of 20 events are not available in an evaluation year, then similar acceptable events from the next year's evaluation period will be included with the data set by the ERO for determining Frequency Response Obligation (FRO) compliance. The first year's small set of data will be reported and used for Bias Setting purposes, but compliance evaluation on the FRO will be done using a 24-month data set.

To assist Balancing Authority preparation for complying with this standard, the ERO will provide quarterly posting of candidate frequency excursion events for the current year FRM calculation. The ERO will post the final list of frequency excursion events used for standard compliance as specified in Attachment A of ~~BAL-003-1~~the standard. The following is a general description of the process that the ERO will use to ensure that BAs can evaluate events during the year in order to monitor their performance throughout the year.

~~Monthly~~

~~Candidate events will be initially screened by the "Frequency Event Detection Methodology" shown on the following link located on the NERC Resources Subcommittee area of the NERC website: http://www.nerc.com/docs/oc/rs/Frequency_Event_Detection_Methodology_and_Criteria_Oct_2011.pdf. Each month's list will be posted by the end of the following month on the NERC website, http://www.nerc.com/filez/rs.html and listed under "Candidate Frequency Events".~~

Quarterly

The ~~monthly~~ event lists will be reviewed quarterly, with the quarters defined as:

- December through February
- March through May
- June through August
- September through November

Based on criteria established in this Procedure~~the "*Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard*"~~, events will be selected to populate the FRS Form 1 for each Interconnection. The FRS Form 1's will be posted on the NERC website, in the Resources Subcommittee (RS) area under the title "Frequency Response Standard Resources". Updated FRS Form 1's will be posted at the end of each quarter listed above after a review by the NERC RS'~~-~~ and Frequency Working Group. While the events on this list are expected to be final, as outlined in the selection criteria, additional events may be considered, if the number of events throughout the year do not create a list of at least 20 events. It is intended that this quarterly posting of updates to the FRS Form 1 would allow BAs to evaluate the events throughout the year, lessening the burden when the yearly posting is made.

Annually

The final FRS Form 1 for each Interconnection, which would contain the events from all four quarters listed above, will be posted as specified in Attachment A. Each ~~Balancing Authority~~BA reports its previous year's Frequency Response Measure (FRM), Frequency Bias Setting and Frequency Bias type (fixed or variable) to the ERO as specified in Attachment A using the final FRS Form 1. The ERO will check for errors and use the FRS Form 1 data to calculate CPS limits and FROs for the upcoming year.

Once the data listed above is fully reviewed, the ERO may adjust the implementation specified in Attachment A for changing the Frequency Bias Settings and CPS limits. This allows flexibility in when each BA implements its settings.

Chapter 2: Process for Adjusting Interconnection Minimum Frequency Bias Setting

This procedure outlines the process the ERO is to use for modifying minimum Frequency Bias Settings to better meet reliability needs. The ERO will adjust the Frequency Bias Setting minimum in accordance with this procedure.
The ERO will post the minimum Frequency Bias Setting values on the ERO website along with other balancing standard limits.

Under BAL-003-~~1~~2, the minimum Frequency Bias Settings will be moved toward the natural Frequency Response in each ~~interconnection~~Interconnection. In the first year, the minimum Frequency Bias Setting for each ~~interconnection~~ Interconnection is shown in Table 2 below. Each Interconnection Minimum Frequency Bias Setting is based on the sum of the non-coincident peak loads for each BA from the currently available FERC 714 Report or equivalent. This non-coincident peak load sum is multiplied by the percentage shown in Table 2 to get the Interconnection Minimum Frequency Bias Setting. The Interconnection Minimum Frequency Bias Setting is allocated among the BAs on an ~~interconnection~~ Interconnection using the same allocation method as is used for the allocation of the Frequency Response Obligation (FRO).

Table 2.1: Frequency Bias Setting Minimums

Interconnection	Interconnection Minimum Frequency Bias Setting (in MW/0.1Hz)
Eastern	0.9% of non-coincident peak load
Western	0.9% of non-coincident peak load
ERCOT	N/A
HQ	N/A

*The minimum Frequency Bias Setting requirement does not apply to a Balancing Authority that is the only Balancing Authority in its Interconnection. These Balancing Authorities are solely responsible for providing reliable frequency control of their Interconnection. These ~~Balancing Authorities~~BAs are responsible for converting frequency error into a megawatt error to provide reliable frequency control, and the imposition of a minimum bias setting greater than the magnitude the Frequency Response Obligation may have the potential to cause control system hunting, and instability in the extreme.

The ERO, in coordination with the regions of each interconnection, will annually review Frequency Bias Setting data submitted by BAs. 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 peak load (expressed in MW/0.1Hz), the minimum Frequency Bias Setting for BAs within that Interconnection may be reduced (in absolute value) in the subsequent years FRS Form 1 based on the technical evaluation and consultation with the regions affected by 0.1 percentage point of peak load (expressed in MW/0.1Hz) to better match that Frequency Bias Setting and natural Frequency Response.

The ERO, in coordination with the regions of each Interconnection, will monitor the impact of the reduction of minimum frequency bias settings, if any, on frequency performance, control performance, and system reliability. If unexpected and undesirable impacts such as, but not limited to, sluggish post-contingency restoration of frequency to schedule or control performance problems occur, then the prior reduction in the minimum frequency bias settings may be reversed, and/or the prospective reduction based on the criterion stated above may not be implemented.

Chapter 3: Interconnection Frequency Response Obligation Methodology

The Interconnection Resource Loss Protection Criteria (RLPC) is calculated based a resource loss in accordance with the following process:

NERC will request BAs to provide their two largest resource loss values and largest resource loss due to an N-1 or N-2 RAS event. This will facilitate comparison between the existing Interconnection RLPC values and the RLPC values in use. This data submission will be needed to complete the calculation of the RLPC and IFRO.

BAs determine the two largest resource losses for the next operating year based on a review of the following items:

- The two largest independent Balancing Contingency Events, each due to a single contingency, identified using system models measured by megawatt loss in a normal system configuration (N-0). (An abnormal system configuration is not used to determine the RLPC.)
- The two largest units in the BA Area, regardless of shared ownership/responsibility.
- The two largest Remedial Action Scheme (RAS) resource losses (if any) which are initiated by single (N-1) contingency events.

The BA provides these two numbers determined above as Resource Loss A and Resource Loss B in the FR Form 1.

The BA should then provide the largest resource loss due to RAS operations (if any) which is initiated by a multiple contingency (N-2) event (RLPC cannot be lower than this value). If this RAS impacts more than a single BA, one BA is asked to take the lead and sum all resources lost due to the RAS event and provide that information.

The calculated RLPC should meet or exceed any credible N-2 resource loss event.

The host BA (or planned host BA) where jointly-owned resources are physically located, should be the only BA to report that resource. The full ratings of the resource, not the fractional shares, should be reported.

Direct-current (DC) ties to asynchronous resources (such as DC ties between Interconnections, or the Manitoba Hydro Dorsey bi-pole ties to their northern asynchronous generation) should be considered as resource losses. DC lines such as the Pacific DC Intertie, which ties two sections of the same synchronous Interconnection together, should not be reported. A single pole block with normal clearing in a monopole or bi-pole high-voltage direct current system is a single contingency.

For a hypothetical four-BA Interconnection, Plant 1, in BA1, has two generators rated at 1200 MW each. Plant 2, in BA2 has a generator rated at 1400 MW. BA2's next largest contingency is 1000 MW. The two largest resource losses for BA3 and BA4 are listed below.

BA1	Resource Loss A = 1200 MW	Resource Loss B = 1200 MW	Both at Plant 1 (N-2)
BA2	Resource Loss A= 1400 MW	Resource Loss B = 1000 MW	Electrically separate
BA3	Resource Loss A = 1000 MW	Resource Loss B = 800 MW	Electrically separate
BA4	Resource Loss A = 1500 MW (DC TIE)	Resource Loss B = 500 MW	Electrically separate

The ERO would apply the RLPC selection methodology described above to determine the RLPC for the Interconnection. Using this methodology, results in the following:

Largest Resource Loss = 1500 MW Second Largest Resource Loss = 1400 MW Summation of two largest resource losses = 2900 MW Interconnection RLPC = 2900 MW

If only the N-2 Event was applied, the RLPC for the Interconnection would be 2400 MW. The summation of the two largest Interconnection Resource Losses will equal or exceed, but never fall short of, the N-2 Event scenario.

In order to evaluate RAS resource loss, single (N-1) and multiple (N-2) contingency events should be evaluated. Hypothetically, in an Interconnection:

BA1 RAS = 2850 MW	N-2 RAS event
BA1 Resource Loss A = 1150 MW	
BA1 Resource Loss B = 800 MW	
BA2 Resource Loss A = 1380 MW	
BA2 Resource Loss B = 1380 MW	
BA3 RAS = 1000 MW	N-1 RAS event
BA3 Resource Loss A = 800 MW	
BA3 Resource Loss B = 700 MW	

In this case, the ERO would determine the RLPC as follows: the summation of the two largest resource losses is 2760 MW. Since the N-2 RAS event exceeds the summation of the two largest single contingency events, the RLPC is the N-2 RAS event, or 2850 MW.

Interconnection RLPC Values

Based on initial review, the numbers below would be representative of the RLPC for each Interconnection.

Eastern Interconnection:
Present RLPC = 4500 MW Load Credit = 0 MW
RESOURCE LOSS A = 1732 MW
RESOURCE LOSS B = 1477 MW
Proposed RLPC = 3209 MW

Western Interconnection:
Present RLPC = 2626 MW Load Credit = 0 MW
RESOURCE LOSS A = 1505 MW
RESOURCE LOSS B = 1344 MW
N-2 RAS = 2850 MW
Proposed RLPC = 2850 MW

ERCOT:
Present RLPC = 2750 MW Load Credit = 1209 MW
RESOURCE LOSS A = 1375 MW
RESOURCE LOSS B = 1375 MW
Proposed RLPC = 2750 MW

Quebec Interconnection:
Present RLPC = 1700 MW Load Credit = 0 MW
RESOURCE LOSS A = 1000 MW
RESOURCE LOSS B = 1000 MW
Proposed RLPC = 2000 MW

Calculation of IFRO Values

The IFRO is calculated using the RLPC (reference is from Table 1 from BAL-003-2):

IFRO = (RLPC-CLR) expressed as MW/0.1Hz
(MDF*10)

MDF is the Maximum Delta Frequency for the specific interconnection as determined in the 2017 Frequency Response Annual Analysis (FRAA).

Interconnection Frequency Response Obligation

Interconnection	Eastern	Western	ERCOT	HQ	Units
Max. Delta Frequency (MDF)	**0.420**	**0.280**	**0.405**	**0.947**	Hz
Resource Loss Protection Criteria (RLPC)	**3,209**	**2,850**	**2,750**	**2,000**	MW
Credit for Load Resources (CLR)			**1,209**		MW
Calculated IFRO	**-784***	**-1018**	**-380**	**-211**	MW/0.1Hz

* Eastern Interconnection IFRO will be stepped down to this level over three years per BAL-003-2.

~~This procedure outlines the process the ERO is to use for determining the Interconnection Frequency Response Obligation (IFRO).~~

~~The following are the formulae that comprise the calculation of the IFROs.~~

$$DF_{Base} = F_{Start} - UFLS$$
$$DF_{CC} = DF_{Base} - CC_{Adj}$$
$$DF_{CBR} = \frac{DF_{CC}}{CB_R}$$
$$MDF = DF_{CBR} - BC'_{Adj}$$
$$ARCC = RCC - CLR$$
$$IFRO = \frac{ARCC}{10 * MDF}$$

~~Where:~~
~~DF_{Base} is the base delta frequency.~~
~~FStart is the starting frequency determined by the statistical analysis.~~
~~UFLS is the highest UFLS trip setpoint for the interconnection.~~
~~CCAdj is the adjustment for the differences between 1-second and sub-second Point C observations for frequency events. A positive value indicates that the sub-second C data is lower than the 1-second data.~~
~~DFCC is the delta frequency adjusted for the differences between 1-second and sub-second Point C observations for frequency events.~~
~~CBR is the statistically determined ratio of the Point C to Value B.~~

~~DFCBR is the delta frequency adjusted for the ratio of the Point C to Value B.~~

~~BC'ADJ is the statistically determined adjustment for the event nadir being below the Value B (Eastern Interconnection only) during primary frequency response withdrawal.~~

~~MDF is the maximum allowable delta frequency.~~

~~RCC is the resource contingency criteria.~~

~~CLR is the credit for load resources.~~

~~ARCC is the adjusted resource contingency criteria adjusted for the credit for load resources.~~

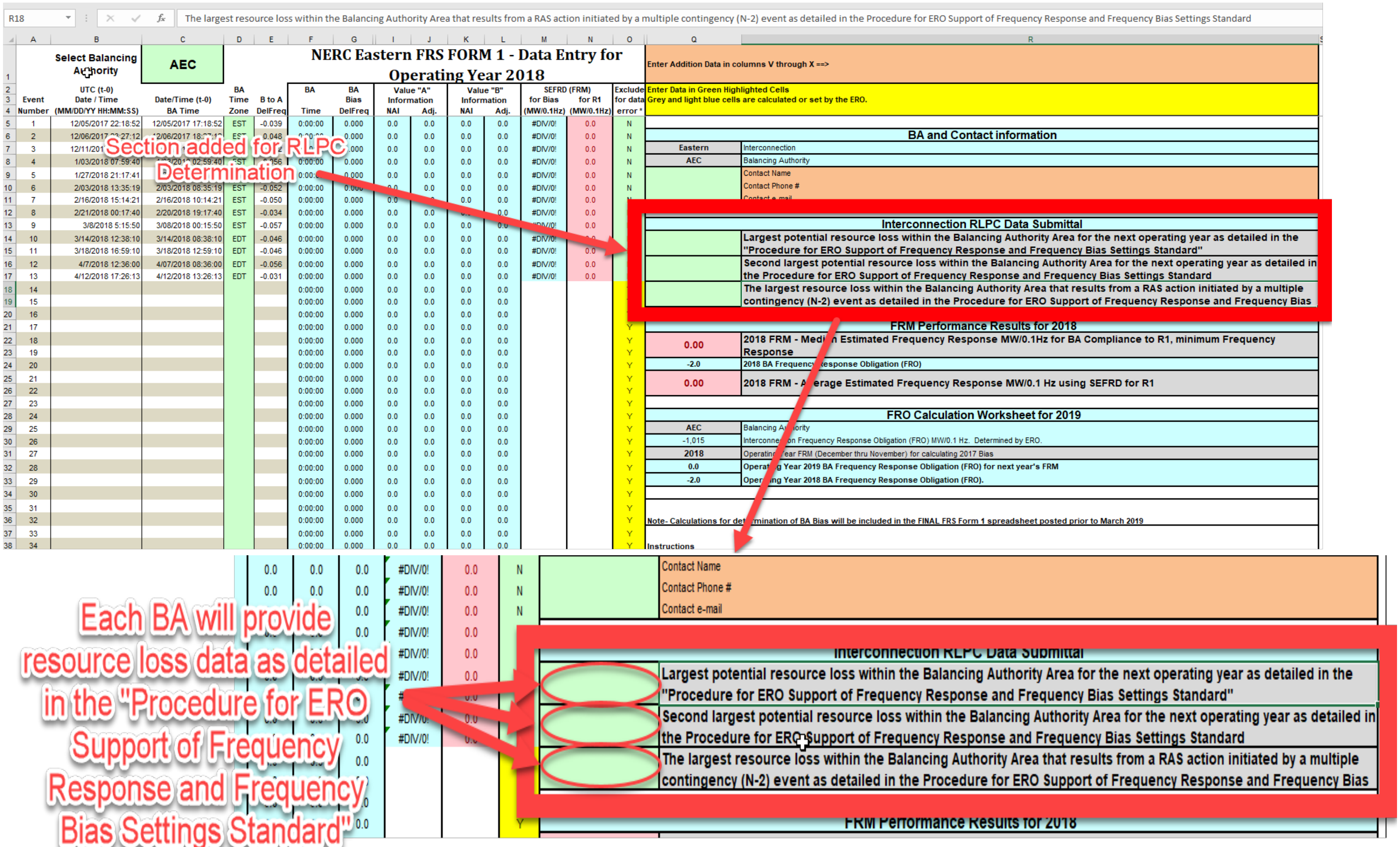
~~IFRO is the interconnection frequency response obligation.~~

FRS Form 1 is a complex spreadsheet. To view the version posted with the Final Draft of the standard, please go to this address:

https://www.nerc.com/pa/Stand/Project201701ModificationstoBAL00311/Eastern%20Int%20FRS_Form_1-2018_Modified%20for%20SDT.xlsm

Modification to FRS Form 1

Each Balancing Authority (BA) including those within a Frequency Response Sharing Group (FRSG) provides data for the determination of the appropriate Interconnection's Resource Loss Protection Criteria (RLPC). In addition to the current practice of providing their frequency response sampling for all four quarters and their Frequency Bias Setting (FBS) calculation, each BA provides requested information regarding determination of resource losses and potential maximum resource loss due to Remedial Action Scheme (RAS) actions as detailed in the "Procedure for ERO Support of Frequency Response and Frequency Bias Setting Standard". For BAs that do not have facilities that meet the defined criteria, the entity would enter "0" in the appropriate cell. It would be expected that "load only" BAs would not have resources to report, as well as "generation only" BAs that have only a single resource. It is also expected that most BAs would not have RAS actions that include loss of resources larger than their reported resource losses. To facilitate the collection of data, the FRS Form 1 has been modified with the addition of the following fields.


R18
The largest resource loss within the Balancing Authority Area that results from a RAS action initiated by a multiple contingency (N-2) event as detailed in the Procedure for ERO Support of Frequency Response and Frequency Bias Settings Standard
Select Balancing Authority
AEC
NERC Eastern FRS FORM 1 - Data Entry for Operating Year 2018
Enter Addition Data in columns V through X ==>
Enter Data in Green Highlighted Cells
Grey and light blue cells are calculated or set by the ERO.
Event Number
UTC (t-0) Date / Time (MM/DD/YY HH:MM:SS)
Date/Time (t-0) BA Time
BA Time Zone
B to A DelFreq
BA Time
BA Bias DelFreq
Value "A" Information NAI Adj.
Value "B" Information NAI Adj.
SEFRD (FRM) for Bias (MW/0.1Hz) for R1 (MW/0.1Hz)
Exclude for data error *
BA and Contact information
Eastern
Interconnection
AEC
Balancing Authority
Contact Name
Contact Phone #
Section added for RLPC Determination
Interconnection RLPC Data Submittal
Largest potential resource loss within the Balancing Authority Area for the next operating year as detailed in the "Procedure for ERO Support of Frequency Response and Frequency Bias Settings Standard"
Second largest potential resource loss within the Balancing Authority Area for the next operating year as detailed in the Procedure for ERO Support of Frequency Response and Frequency Bias Settings Standard
The largest resource loss within the Balancing Authority Area that results from a RAS action initiated by a multiple contingency (N-2) event as detailed in the Procedure for ERO Support of Frequency Response and Frequency Bias
FRM Performance Results for 2018
0.00
2018 FRM - Median Estimated Frequency Response MW/0.1Hz for BA Compliance to R1, minimum Frequency Response
-2.0
2018 BA Frequency Response Obligation (FRO)
0.00
2018 FRM - Average Estimated Frequency Response MW/0.1 Hz using SEFRD for R1
FRO Calculation Worksheet for 2019
AEC
Balancing Authority
-1,015
Interconnection Frequency Response Obligation (FRO) MW/0.1 Hz. Determined by ERO.
2018
Operating Year FRM (December thru November) for calculating 2017 Bias
0.0
Operating Year 2019 BA Frequency Response Obligation (FRO) for next year's FRM
-2.0
Operating Year 2018 BA Frequency Response Obligation (FRO).
Note- Calculations for determination of BA Bias will be included in the FINAL FRS Form 1 spreadsheet posted prior to March 2019
Instructions
Contact Name
Contact Phone #
Contact e-mail
Interconnection RLPC Data Submittal
Largest potential resource loss within the Balancing Authority Area for the next operating year as detailed in the "Procedure for ERO Support of Frequency Response and Frequency Bias Settings Standard"
Second largest potential resource loss within the Balancing Authority Area for the next operating year as detailed in the Procedure for ERO Support of Frequency Response and Frequency Bias Settings Standard
The largest resource loss within the Balancing Authority Area that results from a RAS action initiated by a multiple contingency (N-2) event as detailed in the Procedure for ERO Support of Frequency Response and Frequency Bias
FRM Performance Results for 2018
Each BA will provide resource loss data as detailed in the "Procedure for ERO Support of Frequency Response and Frequency Bias Settings Standard"

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RELIABILITY CORPORATION

Updated

Standards Announcement

Project 2017-01 Modifications to BAL-003-1.1

Final Ballot Open through October 24, 2019

Now Available

A 10-day final ballot for **BAL-003-2 – Frequency Response and Frequency Bias Setting** has been extended through **8 p.m. Eastern, Thursday, October 24, 2019.**

The following documents have been reposted due to identified redline errors. The final ballot has been extended to provide stakeholders adequate time to review the updated documents:

- VRF/VSL Justifications (clean version); and
- VRF/VSL Justifications (redlined version)

Balloting

In the final ballot, votes are counted by exception. Votes from the previous ballot are automatically carried over in the final ballot. Only members of the applicable ballot pools can cast a vote. Ballot pool members who previously voted have the option to change their vote in the final ballot. Ballot pool members who did not cast a vote during the previous ballot can vote in the final ballot.

Members of the ballot pool(s) associated with this project can log in and submit their votes by accessing the Standards Balloting & Commenting System (SBS) here. If you experience issues navigating the SBS, contact Linda Jenkins.

- *If you are having difficulty accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out, contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern).*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

The voting results will be posted and announced after the ballot closes. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process
For more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Standards Developer, Laura Anderson (via email) or at (404) 446-9671.

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Standards Announcement

Project 2017-01 Modifications to BAL-003-1.1

Final Ballot Open through October 21, 2019

Now Available

A 10-day final ballot for **BAL-003-2 – Frequency Response and Frequency Bias Setting** is open through **8 p.m. Eastern, Monday, October 21, 2019.**

Balloting

In the final ballot, votes are counted by exception. Votes from the previous ballot are automatically carried over in the final ballot. Only members of the applicable ballot pools can cast a vote. Ballot pool members who previously voted have the option to change their vote in the final ballot. Ballot pool members who did not cast a vote during the previous ballot can vote in the final ballot.

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BALLOT RESULTS

Ballot Name: 2017-01 Modifications to BAL-003-1.1 BAL-003-2 FN 2 ST
Voting Start Date: 10/10/2019 12:01:00 AM
Voting End Date: 10/24/2019 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 198
Total Ballot Pool: 213
Quorum: 92.96
Quorum Established Date: 10/10/2019 10:38:48 AM
Weighted Segment Value: 100

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	60	1	47	1	0	0	0	7	6
Segment: 2	7	0.7	7	0.7	0	0	0	0	0
Segment: 3	45	1	39	1	0	0	0	5	1
Segment: 4	10	0.6	6	0.6	0	0	0	0	4
Segment: 5	48	1	40	1	0	0	0	5	3
Segment: 6	36	1	33	1	0	0	0	2	1
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	2	0.2	2	0.2	0	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	4	0.4	4	0.4	0	0	0	0	0
Totals:	213	6	179	6	0	0	0	19	15

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Affirmative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Ben Engelby		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		None	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Central Electric Power Cooperative (Missouri)	Michael Bax		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Candace Marshall		Affirmative	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Ayman Samaan		Abstain	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Affirmative	N/A
1	Great Plains Energy - Kansas City Power and Light Co.	James McBee	Douglas Webb	Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro-Qu?bec TransEnergie	Nicolas Turcotte		Affirmative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		None	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Abstain	N/A
1	JEA	Ted Hobson		Affirmative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Trey Melcher		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Bruce Reimer		Affirmative	N/A
1	Muscatine Power and Water	Andy Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Affirmative	N/A
1	New York Power Authority	Salvatore Spagnolo		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Kevin White		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Peak Reliability	Michael Granath		None	N/A
1	Platte River Power Authority	Matt Thompson		Affirmative	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Sean Cavote		Affirmative	N/A
1	Public Utility District No. 1 of Chelan County	Jeff Kimbell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Puget Sound Energy, Inc.	Theresa Rakowsky		Affirmative	N/A
1	Sacramento Municipal Utility District	Arthur Starkovich	Joe Tarantino	Affirmative	N/A
1	Salt River Project	Steven Cobb		Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Seminole Electric Cooperative, Inc.	Bret Galbraith		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell		Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Affirmative	N/A
1	Tennessee Valley Authority	Gabe Kurtz		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Kjersti Drott		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Westar Energy	Allen Klassen	Douglas Webb	Affirmative	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	California ISO	Jamie Johnson		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Affirmative	N/A
2	ISO New England, Inc.	Michael Puscas	Kathleen Goodman	Affirmative	N/A
2	Midcontinent ISO, Inc.	David Zwergel		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Charles Yeung		Affirmative	N/A
3	AEP	Kent Feliks		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras	Tamara Evey	Affirmative	N/A
3	APS - Arizona Public Service Co.	Vivian Moser		Affirmative	N/A
3	Avista - Avista Corporation	Scott Kinney	Rich Hydzik	Affirmative	N/A
3	BC Hydro and Power Authority	Hootan Jarollahi		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Darnez Gresham		Affirmative	N/A
3	Bonneville Power Administration	Ken Lanehome		Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Dominion - Dominion Resources, Inc.	Connie Lowe		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		Affirmative	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Abstain	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Georgia System Operations Corporation	Scott McGough		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Great Plains Energy - Kansas City Power and Light Co.	John Carlson	Douglas Webb	Affirmative	N/A
3	Great River Energy	Brian Glover		Affirmative	N/A
3	Lakeland Electric	Patricia Boody		Affirmative	N/A
3	Lincoln Electric System	Jason Fortik		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Affirmative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	John Stickley		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Abstain	N/A
3	Platte River Power Authority	Wade Kiess		Affirmative	N/A
3	Portland General Electric Co.	Dan Zollner		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Affirmative	N/A
3	Puget Sound Energy, Inc.	Tim Womack		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sacramento Municipal Utility District	Nicole Looney	Joe Tarantino	Affirmative	N/A
3	Salt River Project	Zack Heim		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	Seattle City Light	Laurie Hammack		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	Marc Donaldson		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart	Douglas Webb	Affirmative	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	American Public Power Association	Jack Cashin		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		None	N/A
4	Georgia System Operations Corporation	Andrea Barclay		None	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Affirmative	N/A
4	Sacramento Municipal Utility District	Beth Tincher	Joe Tarantino	Affirmative	N/A
4	Seattle City Light	Hao Li		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Utility Services, Inc.	Brian Evans-Mongeon		None	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Brad Haralson		Affirmative	N/A
5	Austin Energy	Lisa Martin		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Kevin Salsbury		Affirmative	N/A
5	Boise-Kuna Irrigation District - Lucky Peak Power Plant Project	Mike Kukla		Affirmative	N/A
5	Bonneville Power Administration	Scott Winner		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		None	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		Affirmative	N/A
5	City Water, Light and Power of Springfield, IL	Rick Meadows		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dominion - Dominion Resources, Inc.	Rachel Snead		Affirmative	N/A
5	DTE Energy - Detroit Edison Company	Adrian Raducea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Exelon	Cynthia Lee		Affirmative	N/A
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Affirmative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Lakeland Electric	Jim Howard		Affirmative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		None	N/A
5	Lower Colorado River Authority	Teresa Cantwell		Abstain	N/A
5	Manitoba Hydro	Yuguang Xiao		Affirmative	N/A
5	Massachusetts Municipal Wholesale Electric Company	Anthony Stevens		Abstain	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	NaturEner USA, LLC	Eric Smith		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Mahmood Safi		None	N/A
5	Platte River Power Authority	Tyson Archie		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	PSEG - PSEG Fossil LLC	Tim Kucey		Affirmative	N/A
5	Public Utility District No. 1 of Chelan County	Meaghan Connell		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Alex Ybarra		Affirmative	N/A
5	Puget Sound Energy, Inc.	Eleanor Ewry		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Abstain	N/A
5	Southern Company - Southern Company Generation	William D. Shultz		Affirmative	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin		Affirmative	N/A
5	WEC Energy Group, Inc.	Janet OBrien		Affirmative	N/A
5	Westar Energy	Derek Brown	Douglas Webb	Affirmative	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	AEP - AEP Marketing	Yee Chou		Affirmative	N/A
6	APS - Arizona Public Service Co.	Chinedu Ochonogor		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		Affirmative	N/A
6	Bonneville Power Administration	Andrew Meyers		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Louis Guidry	Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Exelon	Becky Webb		Affirmative	N/A
6	FirstEnergy - FirstEnergy Solutions	Ann Carey		None	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Affirmative	N/A
6	Great Plains Energy - Kansas City Power and Light Co.	Jennifer Flandermeyer	Douglas Webb	Affirmative	N/A
6	Great River Energy	Donna Stephenson	Michael Brytowski	Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Manitoba Hydro	Blair Mukanik		Affirmative	N/A
6	Muscatine Power and Water	Nick Burns		Affirmative	N/A
6	New York Power Authority	Thomas Savin		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	Powerex Corporation	Gordon Dobson-Mack		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Luiggi Beretta		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Public Utility District No. 2 of Grant County, Washington	LeRoy Patterson		Affirmative	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Santee Cooper	Michael Brown		Abstain	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Michael Lee		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Rick Applegate		Affirmative	N/A
6	Tennessee Valley Authority	Marjorie Parsons		Affirmative	N/A
6	Westar Energy	Grant Wilkerson	Douglas Webb	Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
8	Roger Zaklukiewicz	Roger Zaklukiewicz		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Affirmative	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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