Exhibit A

Proposed Reliability Standard

Exhibit A

Proposed Reliability Standard

BAL-002-3 (Disturbance Control Performance –

Contingency Reserve for Recovery from a Balancing Contingency Event)

Clean

A. Introduction

1. **Title:** Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

2. **Number:** BAL-002-3

3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

4. **Applicability:**

   4.1. Responsible Entity

   4.1.1. Balancing Authority

   4.1.1.1. A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Reserve Sharing Group.

   4.1.2. Reserve Sharing Group

5. **Effective Date:** See the Implementation Plan for BAL-002-3.

B. Requirements and Measures

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity:

1.3.1 is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert Level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1. If Requirement R1 part 1.3 applies, then dated documentation that demonstrates compliance with Requirement R1 part 1.3 must also be provided.

R2. Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M2. Each Responsible Entity will have the following documentation to show compliance with Requirement R2:

- a dated Operating Process;
- evidence to indicate that the Operating Process has been reviewed and maintained annually; and,
- evidence such as Operating Plans or other operator documentation that demonstrate that the entity determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency are included in this process.

R3. Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration Period resets the beginning of the Contingency Event Recovery Period. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Responsible Entity will have documentation demonstrating its Contingency Reserve was restored within the Contingency Reserve Restoration Period, such as historical data, computer logs or operator logs.

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 Responsible Entity shall retain data or evidence to show compliance for the current year, plus three previous 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 Responsible Entity is found noncompliant, it shall keep information related to the noncompliance 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 Assessment Processes:
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" 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.

1.4. Additional Compliance Information
The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The Responsible Entity achieved less than 100% but at least 90% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period OR The Responsible Entity failed to use CR Form 1 to document a Reportable Balancing Contingency Event.	The Responsible Entity achieved less than 90% but at least 80% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 80% but at least 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.
R2.	The Responsible Entity developed and implemented an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to maintain	N/A	The Responsible Entity developed an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to implement the Operating Process.	The Responsible Entity failed to develop an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency.

	annually the Operating Process.			
R3.	The Responsible Entity restored less than 100% but at least 90% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 90% but at least 80% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 80% but at least 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

CR Form 1

BAL-002-3 Rationales

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	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata
1	September 9, 2010	Filed petition for revisions to BAL-002 Version 1 with the Commission	Revision
1	January 10, 2011	FERC letter ordered in Docket No. RD10-15-00 approving BAL-002-1	
1	April 1, 2012	Effective Date of BAL-002-1	
1a	November 7, 2012	Interpretation adopted by the NERC Board of Trustees	
1a	February 12, 2013	Interpretation submitted to FERC	
2	November 5, 2015	Adopted by NERC Board of Trustees	Complete revision
2	January 19, 2017	FERC Order approved BAL-002-2. Docket No. RM16-7-000	
2	October 2, 2017	FERC letter Order issued approving raising the VRF for Requirement R1 and R2 from Medium to High. Docket No. RD17-6-000.	
3	August 16, 2018	Adopted by NERC Board of Trustees	Revisions to address two FERC directives from Order No. 835
3	TBD	FERC Order approving BAL-002-3	

Exhibit A

Proposed Reliability Standard

BAL-002-3 (Disturbance Control Performance –

Contingency Reserve for Recovery from a Balancing Contingency Event)

Redline

A. Introduction

1. **Title:** Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

2. **Number:** BAL-002-3~~2~~

3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

4. **Applicability:**

   4.1. Responsible Entity

   4.1.1. Balancing Authority

   4.1.1.1. A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Reserve Sharing Group.

   4.1.2. Reserve Sharing Group

5. **Effective Date:** See the Implementation Plan for BAL-002-3~~2~~.

B. Requirements and Measures

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity:

1.3.1 is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that~~the Responsible Entity~~:

- is ~~a Balancing Authority~~ experiencing a Reliability Coordinator declared Energy Emergency Alert Level~~ or is a Reserve Sharing Group whose member, or members, are experiencing a Reliability Coordinator declared Energy Emergency Alert level~~, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1. If Requirement R1 part 1.3 applies, then dated documentation that demonstrates compliance with Requirement R1 part 1.3 must also be provided.

R2. Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M2. Each Responsible Entity will have the following documentation to show compliance with Requirement R2:

- a dated Operating Process;
- evidence to indicate that the Operating Process has been reviewed and maintained annually; and,
- evidence such as Operating Plans or other operator documentation that demonstrate that the entity determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency are included in this process.

R3. Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration Period resets the beginning of the Contingency Event Recovery Period. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Responsible Entity will have documentation demonstrating its Contingency Reserve was restored within the Contingency Reserve Restoration Period, such as historical data, computer logs or operator logs.

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.

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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.

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Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

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1.3. Compliance Monitoring and Assessment Processes:

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1.4. Additional Compliance Information

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

Table of Compliance Elements

R #	Violation Severity Levels			
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R2.	The Responsible Entity developed and implemented an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to maintain	N/A	The Responsible Entity developed an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to implement the Operating Process.	The Responsible Entity failed to develop an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency.

	annually the Operating Process.			
R3.	The Responsible Entity restored less than 100% but at least 90% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 90% but at least 80% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 80% but at least 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document~~

CR Form 1

BAL-002-3 Rationales

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	February 14, 2006	Revised graph on page 3, “10 min.” to “Recovery time.” Removed fourth bullet.	Errata
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1	April 1, 2012	Effective Date of BAL-002-1	
1a	November 7, 2012	Interpretation adopted by the NERC Board of Trustees	
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2	November 5, 2015	Adopted by NERC Board of Trustees	Complete revision
2	January 19, 2017	FERC Order approved BAL-002-2. Docket No. RM16-7-000	
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3	August 16, 2018	Adopted by NERC Board of Trustees	Revisions to address two FERC directives from Order No. 835
3	TBD	FERC Order approving BAL-002-3	

Exhibit B

Implementation Plan

Implementation Plan

Project 2017-06 Modifications to BAL-002-2

Requested Approvals

- BAL-002-3 Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

Requested Retirements

- BAL-002-2 Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

Applicable Entities

- Balancing Authority
- Reserve Sharing Group

Effective Date

The effective date for proposed Reliability Standard BAL-002-3 is provided below:

Where approval by an applicable governmental authority is required, Reliability Standard BAL-002-3 shall become effective the first day of the first calendar quarter that is six (6) calendar months after the effective date of the applicable governmental authority's order approving the standards and terms, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard BAL-002-3 shall become effective on the first day of the first calendar quarter that is six (6) calendar months after the date the standards and terms are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Current NERC Reliability Standards

The existing standard BAL-002-2 shall be retired immediately prior to the effective date of the proposed BAL-002-3 standard.

Exhibit D

Summary of Development History and Complete Record of Development

Summary of Development History

Summary of Development History

The development record for proposed Reliability Standard BAL-002-3 is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team selected to lead each project in accordance with Section 4.3 of the NERC Standards Process manual.[2] For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the Standard Drafting Team is included in Exhibit F.

II. Standard Development History

A. Standard Authorization Request Development

The Standard Authorization Request ("SAR") for Project 2017-06 – Modifications to BAL-002-2 - Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event was posted for a 30-day comment period from June 20, 2017 through July 20, 2017. The final SAR was posted on March 13, 2018. Following two solicitations for nominations, the Standards Committee ("SC") appointed a SAR drafting team at its October 18, 2017 meeting. The SAR was approved by the SC on February 14, 2018.

B. First Posting – Comment Period, Initial Ballot and Non-binding Poll

Proposed Reliability Standard BAL-002-3, the associated Implementation Plan, and the Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") were posted for a 45-

1 Section 215(d)(2) of the Federal Power Act; 16 U.S.C. § 824(d) (2) (2012).
2 The NERC Standard Processes Manual is available at https://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

day formal public comment period from March 22, 2018 through May 8, 2018, with a parallel Initial Ballot and Non-binding Poll held during the last 10 days of the comment period from April 27, 2018 through May 7, 2018. The initial ballot received 81.82% quorum, and 69.46% approval. The non-binding pill received 80% quorum and 77.19% of supportive opinions. There were 30 responses, including comments from approximately 115 different individuals and approximately 87 companies representing all 10 industry segments.[3]

C. Final Draft

Proposed Reliability Standard BAL-002-3 was posted for a 10-day final ballot period from July 5, 2018 through July 16, 2018. The Proposed Reliability Standard received a quorum of 84.42% and an approval rating of 71.85%.

D. Board of Trustees Approval

Proposed Reliability Standard BAL-002-3 was adopted by the NERC Board of Trustees on August 16, 2018.[4]

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[3] NERC, Consideration of Comments, Project 2017-06 - – Modifications to BAL-002-2, https://www.nerc.com/pa/Stand/Project_201706_Modifications_to_BAL0022_DL/2017-06_Mod_to_BAL-002_Consideration_of_Comments_07052018.pdf.

[4] NERC, Board of Trustees Agenda Package, Agenda Item 7c (BAL-002-3 Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event), https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Open_Meeting_Agenda_Package_August_16_2018.pdf.

Complete Record of Development

Project 2017-06 Modifications to BAL-002-2

Related Files

Status

The final ballot for **BAL-002-3 Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event** concluded **8 p.m. Eastern, Monday, July 16, 2018.** The voting results are available via the link below. The standard will be submitted to the Board of Trustees for adoption then filed with the appropriate regulatory authorities.

Background

On January 19, 2017, FERC issued an order approving Reliability Standard BAL-002-2. FERC Order also directed NERC to make two modifications to the BAL-002-2 standard and revise two VRFs. The revision for the VRFs will be handled outside of this SAR.

With regard to FERC's directed modifications to BAL-002-2, the order stated:

"Accordingly, we direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require Balancing Authorities (BA) or Reserve Sharing Groups (RSG): (1) to notify the reliability coordinator of the conditions set forth in Requirement R1, Part 1.3.1 preventing it from complying with the 15-minute ACE recovery period; and (2) to provide the reliability coordinator with its ACE recovery plan, including a target recovery time. NERC may also propose an equally efficient and effective alternative."

Standard(s) Affected – BAL-002-2

Purpose / Industry Need

The primary goal of this SAR is to allow the standard drafting team (SDT) for Project 2017-06, Disturbance Control to modify standard BAL-002-2 to address the directives of the January 19, 2017 FERC Order, and to ensure consistency within the NERC body of Reliability Standards.

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft BAL-002-3 Clean (23) | Redline (24) to Last Approved Implementation Plan (25)	Final Ballot Info (26) Vote	07/05/18 - 07/16/18	Ballot Results (27)	
Draft 1 BAL-002-3 Clean (11) | Redline (12) to Last Approved	Initial Ballot and Non-binding Poll	04/27/18 - 05/08/18	Ballot Results (18) Non-binding Poll Results (19)	

Implementation Plan **(13)** **Supporting Materials** Unofficial Comment Form (Word) **(14)** Rationales for BAL-002-3 **(15)**	Updated Info **(16)** Info **(17)** Vote	Extended an additional day to reach quorum		
	Comment Period Info **(20)** Submit Comments	03/22/18 - 05/08/18	Comments Received **(21)**	Consideration of Comments**(22)**
	Join Ballot Pools	03/22/18 - 04/20/18		
Standards Authorization Request **(10)**	For Informational Purposes Only	03/13/18		
Supplemental Standards Authorization Request Drafting Team Nominations **Supporting Materials** Unofficial Nomination Form (Word) **(8)**	Supplemental Nomination Period Info **(9)** Submit Nominations	07/27/17 - 08/09/17		

Standards Authorization Request **(3)** **Supporting Materials** Unofficial Comment Form (Word) **(4)**	Comment Period Info **(5)** Submit Comments	06/20/17 - 07/20/17	Comments Received **(6)**	Consideration of Comments **(7)**
Standards Authorization Request Drafting Team Nominations **Supporting Materials** Unofficial Nomination Form (Word) **(1)**	Nomination Period Info **(2)** Submit Nominations	06/20/17 - 07/03/17		

Unofficial Nomination Form

Project 2017-06 Modifications to BAL-002-2 Standards Authorization Request 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 2017-06 Modifications to BAL-002-2 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 2017-06 Modifications to BAL-002-2

The primary goal of this SAR is to allow the standard drafting team (SDT) for Project 2017-06, Disturbance Control to modify standard BAL-002-2 to address the directives of the January 19, 2017 FERC Order, and to ensure consistency within the NERC body of Reliability Standards.

On January 19, 2017, FERC issued an order directing the ERO to develop modifications to standard BAL-002-2 to address their concerns regarding the 15-minute recovery period set forth in Requirement R1. In the order, FERC stated:

> "Accordingly, we direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require Balancing Authorities (BA) or Reserve Sharing Groups (RSG): (1) to notify the reliability coordinator of the conditions set forth in Requirement R1, Part 1.3.1 preventing it from complying with the 15-minute ACE recovery period; and (2) to provide the reliability coordinator with its ACE recovery plan, including a target recovery time. NERC may also propose an equally efficient and effective alternative."

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 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.

Standards affected: BAL-002-2

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 2017-06 Modifications to BAL-002-2

Nomination Period Open through July 3, 2017

Now Available

Nominations are being sought for Standards Authorization Request drafting team members through **8 p.m. Eastern, Monday, July 3, 2017**.

Use the electronic form to submit a nomination. If you experience any difficulties in using the electronic form, contact Wendy Muller. An unofficial Word version of the nomination form is posted on the 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 unofficial nomination form for additional information.

Next Steps

The Standards Committee is expected to appoint members to the team July 2017. Nominees will be notified shortly after they have been appointed.

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

For more information or assistance 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

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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-002-2 – Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event		
Date Submitted:			
SAR Requester Information			
Name:	Darrel Richardson		
Organization:	NERC Staff		
Telephone:	609.613.1848	Email:	darrel.richardson@nerc.net
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of Existing Standard	
☒ Revision to Existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
On January 19, 2017, FERC issued an order directing the ERO to develop modifications to standard BAL-002-2 to address their concerns regarding the 15-minute recovery period set forth in Requirement R1. In the order, FERC stated: “Accordingly, we direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require Balancing Authorities (BA) or Reserve Sharing Groups (RSG): (1) to notify the reliability coordinator of the conditions set forth in Requirement R1, Part 1.3.1 preventing it from complying with

SAR Information
the 15-minute ACE recovery period; and (2) to provide the reliability coordinator with its ACE recovery plan, including a target recovery time. NERC may also propose an equally efficient and effective alternative." Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard, 158 FERC ¶ 61,030 at P 37 (2017) ("FERC Order"). *See also, id.*, at P 2 and PP 35-36.
Purpose or Goal (How does this request propose to address the problem described above?):
The primary goal of this SAR is to allow the standard drafting team (SDT) for Project 2017-06, Disturbance Control to modify standard BAL-002-2 to address the directives of the January 19, 2017 FERC Order, and to ensure consistency within the NERC body of Reliability Standards.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objective of this SAR is to provide clear, unambiguous requirements to address the directives in the January 19, 2017 FERC Order regarding the recovery from a Balancing Contingency Event, or alternatively propose modifications that address the Commission concerns.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall modify the standard, Violation Risk Factors, Violation Severity Levels, and implementation plan and shall work with compliance on an accompanying RSAW to address the FERC Order directives described above.
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.)
The SDTs execution of this SAR requires the SDT to address the FERC Order directives described above or alternatively propose modifications that address the Commission concerns in the FERC Order. This SAR will specifically address either (A) revising BAL-002-2 to require that BAs and RSGs: (1) notify the Reliability Coordinator that the BA or RSG cannot comply with the 15-minute ACE recovery period due to existence of the conditions as set forth in Requirement R1, Part 1.3.1; and (2) provide the Reliability Coordinator with an ACE recovery plan that includes a target recovery time; or (B) proposing an equally efficient and effective alternative.

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
None	

Related SARs	
SAR ID	Explanation
None	

Regional Variances	
Region	Explanation
ERCOT	None.
FRCC	None.
MRO	None.
NPCC	None.
RFC	None.

Regional Variances	
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

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Project 2017-06 Modifications to BAL-002-2 Standards Authorization Request

Do not use this form for submitting comments. Use the electronic form to submit comments on the Standards Authorization Request (SAR) for **BAL-002-2 Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event**. The electronic form must be submitted by **8 p.m. Eastern, Thursday, July 20, 2017**.

Documents and information about this project are available on the Project 2017-06 Modifications to BAL-002-2 page. If you have questions, contact Senior Standards Developer, Darrel Richardson (via email) or at (609) 613-1848.

Background

On January 19, 2017, FERC issued an order directing the ERO to develop modifications to standard BAL-002-2 to address their concerns regarding the 15-minute recovery period set forth in Requirement R1. In the order, FERC stated:

> "Accordingly, we direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require Balancing Authorities (BA) or Reserve Sharing Groups (RSG): (1) to notify the reliability coordinator of the conditions set forth in Requirement R1, Part 1.3.1 preventing it from complying with the 15-minute ACE recovery period; and (2) to provide the reliability coordinator with its ACE recovery plan, including a target recovery time. NERC may also propose an equally efficient and effective alternative."

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

Questions

1. The SDTs execution of this Standards Authorization Request (SAR) requires the SDT to address the FERC Order directives or alternatively propose modifications that address the Commission concerns in the FERC Order. This SAR will specifically address revising BAL-002-2 to require that BAs and RSGs: (1) notify the Reliability Coordinator that the BA or RSG cannot comply with the 15-minute ACE recovery period due to existence of the conditions as set forth in Requirement R1, Part 1.3.1; and (2) provide the Reliability Coordinator with an ACE recovery plan that includes a target recovery time. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

   ☐ Yes
   ☐ No

   Comments:

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

   ☐ Yes
   ☐ No

   Comments:

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RELIABILITY CORPORATION

Standards Announcement

Project 2017-06 Modifications to BAL-002-2 Standards Authorization Request

Informal Comment Period Open through July 20, 2017

Now Available

A 30-day informal comment period on the Standards Authorization Request (SAR) for **BAL-002-2 Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event**, is open through **8 p.m. Eastern, Thursday, July 20, 2017**.

Commenting
Use the electronic form to submit comments on the SAR. If you experience any difficulties using the electronic form, contact Wendy Muller. 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 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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404-446-2560 | www.nerc.com

Comment Report

Project Name:	2017-06 Modifications to BAL-002-2 | Standards Authorization Request
Comment Period Start Date:	6/20/2017
Comment Period End Date:	7/20/2017
Associated Ballots:	

There were 21 sets of responses, including comments from approximately 72 different people from approximately 48 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The SDTs execution of this Standards Authorization Request (SAR) requires the SDT to address the FERC Order directives or alternatively propose modifications that address the Commission concerns in the FERC Order. This SAR will specifically address revising BAL-002-2 to require that BAs and RSGs: (1) notify the Reliability Coordinator that the BA or RSG cannot comply with the 15-minute ACE recovery period due to existence of the conditions as set forth in Requirement R1, Part 1.3.1; and (2) provide the Reliability Coordinator with an ACE recovery plan that includes a target recovery time. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

2. 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
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					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
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

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
					Lonnie Lindekugel	Southwest Power Pool Inc.	2	SPP RE
					Mahmood Safi	Omaha Public Power District	5	SPP RE
PPL - Louisville Gas and Electric Co.	Shelby Wade	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Charlie Freibert	LG&E and KU Energy, LLC	3	SERC
					Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Dan Wilson	LG&E and KU Energy, LLC	5	SERC
					Linn Oelker	LG&E and KU Energy, LLC	6	SERC

1. The SDTs execution of this Standards Authorization Request (SAR) requires the SDT to address the FERC Order directives or alternatively propose modifications that address the Commission concerns in the FERC Order. This SAR will specifically address revising BAL-002-2 to require that BAs and RSGs: (1) notify the Reliability Coordinator that the BA or RSG cannot comply with the 15-minute ACE recovery period due to existence of the conditions as set forth in Requirement R1, Part 1.3.1; and (2) provide the Reliability Coordinator with an ACE recovery plan that includes a target recovery time. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Currently there is no requirement for a Reserve Sharing Group to have a 24 hour, manned, operations center. This would be required if this proposal is implemented. Furthermore, it would also require the Reserve Sharing Group to have authority in some manner over the participating BAs to devise and implement a recovery plan. A proposed alternative could be that BAs that are a part of a RSG must notify their RC if they will not be able to recover their individual ACE in the recovery period as well as providing their recovery plan and target recovery time.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Please see response to Queston #2.	
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	

The Cityy Light subjet amtter expert feels that there should be no requirement that forces a Reserve Sharing Group to have a 24 hour a day operations center. An alternative would be for BA's that are part of an RSG and cause the RSG to be in a disturbance provide the Reliability Coordinator with an ACE recovery plan if they will not be able to recover their ACE in 15 minutes.

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 provides clarity on what the FERC Order is requiring and the situation that has been identified in Requirement R1 Part 1.3.1 of the Standard. From our perspective, there may be some confusion on what goals that need to be accomplished for a Responsible Entity pertaining to this requirement. It's not clear on if a the event drives the situation in to 1.3.1 or b has the EEA Event already occurred and then the Responsible Entity needs to notify the RC about not meeting their recovery time as well as submitting a Recovery Plan. Also, we recommend that if the FERC Order addresses a then BAL-002-2 may be the appropriate document to conduct the proposed revisions. However, if the concerns are more applicable to b then the group would recommend making the appropriate revisions to the EOP-011-1 Standard.

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 use of "15-minute ACE recovery period" in the SAR. We believe the SDT should have clear direction to instead leverage the previously NERC Glossary-defined term, "Contingency Event Recovery Period." This term is referenced frequently within the standard and aligns with the efforts of the previous Standard Drafting Team.

Likes 0	
Dislikes 0	

Response

Dori Quam - NorthWestern Energy - 1 - WECC

Answer	Yes
Document Name	
Comment	

In its comments to FERC's Notice of Proposed Rulemaking (NOPR) in Docket No. RM16-7-000, Arizona Public Service Company (APS) outlined a proposal regarding notice to the RC when the extenuating conditions listed in Requirement R1.3.1 are met and the BA is unable to recover its ACE within the 15-minute recovery period. This proposal addressed FERC's concerns with extension of the 15-minute ACE recovery period, but also allowed appropriate flexibility to BAs when extenuating circumstances are present. (Order No. 835, P 36.)

NorthWestern Energy agrees with the proposal that was outlined by APS in its comments to the FERC NOPR. (APS Comments, Accession No. 20160720-2146, Section II-A, pages 3–9.)

Likes 0	
Dislikes 0	
Response	

John Williams - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5

Answer	Yes
Document Name	
Comment	
Likes 1	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott
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	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
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	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 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	
Mike Smith - Manitoba Hydro - 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	
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	
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	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

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

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We thank you for this opportunity to provide these comments.	
Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1 - WECC	
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	
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	
Mike Smith - Manitoba Hydro - 1,3,5,6	
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	
Laura Nelson - IDACORP - Idaho Power Company - 1	
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	
Kasey Bohannon - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
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	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
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	
John Williams - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	No
Document Name	
Comment	
Likes 1	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
The IRC Standards Review Committee (SRC) provides these comments: As one of the "alternative modifications" the SRC proposes the SDT consider converting the Standard to a communication guide (developed under the auspices of the NERC OC) that could be converted to a standard if such a need were identified by the RCs.	
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 evaluate the expansion of SAR that are associated with part 1.3.2 of the Standard. Our concern pertains to contingencies impacting frequency that is outside of the Responsible Entity's area that has a significant impact on the Responsible Entity meeting the 15 minute recovery.	
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	
Duke Energy agrees that the SAR aligns with the directive from FERC, and also agrees with the scope of this project as written currently.	
Likes 0	
Dislikes 0	
Response	

Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak appreciates the opportunity to provide comments on the BAL-002-2 SAR. Peak requests consideration be given to intended and/or unintended expectations resulting from the provision of the information to the Reliability Coordinator that may or may not be covered by additional NERC Reliability Standards.	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
"The objective of this SAR is to provide clear, unambiguous requirements to address the directives in the January 19, 2017 FERC Order regarding the recovery from a Balancing Contingency Event, or alternatively propose modifications that address the Commission concerns." Since BAL-002-2 is addressing recovery from a **Reportable** Balancing Contingency Event (as distinct from a separately defined [non-reportable] Balancing Contingency Event), and since the FERC Order requires NERC to develop modifications regarding such **Reportable** events, in order to avoid any ambiguity or confusion we recommend that the SAR Objective be revised to state: "The objective of this SAR is to provide clear, unambiguous requirements to address the directives in the January 19, 2017 FERC Order regarding the recovery from a **Reportable** Balancing Contingency Event, or alternatively propose modifications that address the Commission concerns."	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	

Comment	
PacifiCorp is concerned that (1) the requirement to notify the reliability coordinator of the conditions set forth in Requirement R1, Part 1.3.1 preventing it from complying with the 15-minute ACE recovery period; and (2) to provide the reliability coordinator with its ACE recovery plan, including a target recovery time, will be distracting requirements as the balancing area operators are working towards recovery in the 15-minute period. Setting aside recovering from the event to provide notification to the reliability coordinator could impede efforts towards the recovery itself. We fail to see the value in these additional requirements and wonder if is this more suitable for the Eastern Interconnection – Western Interconnection power pool agencies are not 7x24 shops.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
In order to provide clear, unambiguous requirements to address the FERC directive, Texas RE recommends the standard drafting team (SDT) consider specifying a time-frame in which the notification and provision of a recovery plan is expected to occur. Developing a recovery plan and target recovery time may not be feasible within 15 minutes, so it may be more practical to require notification to the Reliability Coordinator (RC) within 15 minutes of the event, and provision of a recovery plan within an agreed upon time-frame.	
Likes 0	
Dislikes 0	
Response	

Consideration of Comments

Project Name:	2017-06 Modifications to BAL-002-2 | Standards Authorization Request
Comment Period Start Date:	6/20/2017
Comment Period End Date:	7/20/2017
Associated Ballots:	

There were 21 sets of responses, including comments from approximately 72 different people from approximately 48 companies representing the 10 Industry Segments as shown in the table on the following pages.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Questions

1. The SDTs execution of this Standards Authorization Request (SAR) requires the SDT to address the FERC Order directives or alternatively propose modifications that address the Commission concerns in the FERC Order. This SAR will specifically address revising BAL-002-2 to require that BAs and RSGs: (1) notify the Reliability Coordinator that the BA or RSG cannot comply with the 15-minute ACE recovery period due to existence of the conditions as set forth in Requirement R1, Part 1.3.1; and (2) provide the Reliability Coordinator with an ACE recovery plan that includes a target recovery time. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.

2. 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
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					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
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC		Pawel Krupa	Seattle City Light	1	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
				Seattle City Light Ballot Body	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
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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					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	6	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Power and Light Co.		
					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
					Lonnie Lindekugel	Southwest Power Pool Inc.	2	SPP RE
					Mahmood Safi	Omaha Public Power District	5	SPP RE
PPL - Louisville Gas and Electric Co.	Shelby Wade	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Charlie Freibert	LG&E and KU Energy, LLC	3	SERC
					Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Dan Wilson	LG&E and KU Energy, LLC	5	SERC
					Linn Oelker	LG&E and KU Energy, LLC	6	SERC

1. ***The SDTs execution of this Standards Authorization Request (SAR) requires the SDT to address the FERC Order directives or alternatively propose modifications that address the Commission concerns in the FERC Order. This SAR will specifically address revising BAL-002-2 to require that BAs and RSGs: (1) notify the Reliability Coordinator that the BA or RSG cannot comply with the 15-minute ACE recovery period due to existence of the conditions as set forth in Requirement R1, Part 1.3.1; and (2) provide the Reliability Coordinator with an ACE recovery plan that includes a target recovery time. Do you agree with this proposed revision? If not, please provide specific language on the proposed revision.***

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Currently there is no requirement for a Reserve Sharing Group to have a 24 hour, manned, operations center. This would be required if this proposal is implemented. Furthermore, it would also require the Reserve Sharing Group to have authority in some manner over the participating BAs to devise and implement a recovery plan. A proposed alternative could be that BAs that are a part of a RSG must notify their RC if they will not be able to recover their individual ACE in the recovery period as well as providing their recovery plan and target recovery time.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SAR DT understands and agrees with your concern. The SAR DT will recommend to the SDT to modify the language to provide clarity to Requirement R1 Part 1.3.1 with respect to the responsible entity communicating with the RC.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No

Document Name	
Comment	
Please see response to Queston #2.	
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	
The Cityy Light subjet amtter expert feels that there should be no requirement that forces a Reserve Sharing Group to have a 24 hour a day operations center. An alternative would be for BA's that are part of an RSG and cause the RSG to be in a disturbance provide the Reliability Coordinator with an ACE recovery plan if they will not be able to recover their ACE in 15 minutes.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SAR DT understands and agrees with your concern. The SAR DT will recommend to the SDT to modify the language to provide clarity to Requirement R1 Part 1.3.1.	
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 provides clarity on what the FERC Order is requiring and the situation that has been identified in Requirement R1 Part 1.3.1 of the Standard. From our perspective, there may be some confusion on what goals that need to be accomplished for a Responsible Entity pertaining to this requirement. It's not clear on if a the event drives the situation in to 1.3.1 or b has the EEA Event already occurred and then the Responsible Entity needs to notify the RC about not meeting their recovery time as well as submitting a Recovery Plan. Also, we recommend that if the FERC Order addresses a then BAL-002-2 may be the appropriate document to conduct the proposed revisions. However, if the concerns are more applicable to b then the group would recommend making the appropriate revisions to the EOP-011-1 Standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SAR DT understands and agrees with your concern. The SAR DT will recommend to the SDT to modify the language to provide clarity to Requirement R1 Part 1.3.1.	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We caution the use of "15-minute ACE recovery period" in the SAR. We believe the SDT should have clear direction to instead leverage the previously NERC Glossary-defined term, "Contingency Event Recovery Period." This term is referenced frequently within the standard and aligns with the efforts of the previous Standard Drafting Team.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SAR DT agrees that defined terms should be used within the standard.	
Dori Quam - NorthWestern Energy - 1 - WECC	
Answer	Yes
Document Name	
Comment	
In its comments to FERC's Notice of Proposed Rulemaking (NOPR) in Docket No. RM16-7-000, Arizona Public Service Company (APS) outlined a proposal regarding notice to the RC when the extenuating conditions listed in Requirement R1.3.1 are met and the BA is unable to recover its ACE within the 15-minute recovery period. This proposal addressed FERC's concerns with extension of the 15-minute ACE recovery period, but also allowed appropriate flexibility to BAs when extenuating circumstances are present. (Order No. 835, P 36.) NorthWestern Energy agrees with the proposal that was outlined by APS in its comments to the FERC NOPR. (APS Comments, Accession No. 20160720-2146, Section II-A, pages 3–9.)	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT will consider this information when developing modifications to the standard.	
John Williams - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 1	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott
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	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
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	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Laura Nelson - IDACORP - Idaho Power Company - 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	

Mike Smith - Manitoba Hydro - 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	
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	
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	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We thank you for this opportunity to provide these comments.	
Likes 0	
Dislikes 0	
Response	
Dori Quam - NorthWestern Energy - 1 - WECC	
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	
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	
Mike Smith - Manitoba Hydro - 1,3,5,6	
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	
Laura Nelson - IDACORP - Idaho Power Company - 1	
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	
Kasey Bohannon - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
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	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
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	
John Williams - Tallahassee Electric (City of Tallahassee, FL) - 1,3,5	
Answer	No
Document Name	
Comment	
Likes 1	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
The IRC Standards Review Committee (SRC) provides these comments: As one of the “alternative modifications” the SRC proposes the SDT consider converting the Standard to a communication guide (developed under the auspices of the NERC OC) that could be converted to a standard if such a need were identified by the RCs.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SAR DT is unsure as to the issue you are raising. However, if you are proposing a communication guide instead of this SAR, the SAR DT believes that there is still clarity necessary to resolve the ambiguity highlighted in Requirement R1 Part 1.3.1 and to address the FERC order. In addition, the SAR DT will recommend to the NERC OC to review the existing Operating Reserve Management Guideline to ensure the communication issues are considered.	
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 evaluate the expansion of SAR that are associated with part 1.3.2 of the Standard. Our concern pertains to contingencies impacting frequency that is outside of the Responsible Entity's area that has a significant impact on the Responsible Entity meeting the 15 minute recovery.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The scope of this SAR is explicitly and exclusively addressing the FERC Order directives. However, if you believe additional modifications are necessary, you may submit a SAR that addresses your concerns.	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	

Duke Energy agrees that the SAR aligns with the directive from FERC, and also agrees with the scope of this project as written currently.	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment.	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Peak appreciates the opportunity to provide comments on the BAL-002-2 SAR. Peak requests consideration be given to intended and/or unintended expectations resulting from the provision of the information to the Reliability Coordinator that may or may not be covered by additional NERC Reliability Standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SAR DT understands your concern and will recommend to the SDT that it consider potentially affected standards.	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	

"The objective of this SAR is to provide clear, unambiguous requirements to address the directives in the January 19, 2017 FERC Order regarding the recovery from a Balancing Contingency Event, or alternatively propose modifications that address the Commission concerns." Since BAL-002-2 is addressing recovery from a **Reportable** Balancing Contingency Event (as distinct from a separately defined [non-reportable] Balancing Contingency Event), and since the FERC Order requires NERC to develop modifications regarding such **Reportable** events, in order to avoid any ambiguity or confusion we recommend that the SAR Objective be revised to state: "The objective of this SAR is to provide clear, unambiguous requirements to address the directives in the January 19, 2017 FERC Order regarding the recovery from a **Reportable** Balancing Contingency Event, or alternatively propose modifications that address the Commission concerns."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDTs are instructed to develop clear and unambiguous language in the standard and therefore, no modifications to the SAR are necessary.	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
PacifiCorp is concerned that (1) the requirement to notify the reliability coordinator of the conditions set forth in Requirement R1, Part 1.3.1 preventing it from complying with the 15-minute ACE recovery period; and (2) to provide the reliability coordinator with its ACE recovery plan, including a target recovery time, will be distracting requirements as the balancing area operators are working towards recovery in the 15-minute period. Setting aside recovering from the event to provide notification to the reliability coordinator could	

impede efforts towards the recovery itself. We fail to see the value in these additional requirements and wonder if is this more suitable for the Eastern Interconnection – Western Interconnection power pool agencies are not 7x24 shops.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SAR DT understands and agrees with your concern. The SAR DT will recommend to the SDT to modify the language to provide clarity to Requirement R1 Part 1.3.1 with respect to the responsible entity, the BA, communicating with the RC.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
In order to provide clear, unambiguous requirements to address the FERC directive, Texas RE recommends the standard drafting team (SDT) consider specifying a time-frame in which the notification and provision of a recovery plan is expected to occur. Developing a recovery plan and target recovery time may not be feasible within 15 minutes, so it may be more practical to require notification to the Reliability Coordinator (RC) within 15 minutes of the event, and provision of a recovery plan within an agreed upon time-frame.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT will consider your comments while developing the language to address the directives from the FERC Order.	

End of Report

Unofficial Nomination Form

Project 2017-06 Modifications to BAL-002-2
Standards 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 2017-06 Modifications to BAL-002-2 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 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 2017-06 Modifications to BAL-002-2

The primary goal of this SAR is to allow the standard drafting team (SDT) for Project 2017-06, Disturbance Control to modify standard BAL-002-2 to address the directives of the January 19, 2017 FERC Order, and to ensure consistency within the NERC body of Reliability Standards.

On January 19, 2017, FERC issued an order directing the ERO to develop modifications to standard BAL-002-2 to address their concerns regarding the 15-minute recovery period set forth in Requirement R1. In the order, FERC stated:

> "Accordingly, we direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require Balancing Authorities (BA) or Reserve Sharing Groups (RSG): (1) to notify the reliability coordinator of the conditions set forth in Requirement R1, Part 1.3.1 preventing it from complying with the 15-minute ACE recovery period; and (2) to provide the reliability coordinator with its ACE recovery plan, including a target recovery time. NERC may also propose an equally efficient and effective alternative."

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 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.

Standards affected: BAL-002-2

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 2017-06 Modifications to BAL-002-2

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 20 through July 3, 2017), you do not need to resubmit your nomination.

The nomination period is being reopened at the request of the Standards Committee (SC). There was considerable overlap in the nominations received for this project and Project 2017-01 Modifications to BAL-003-1.1. The SC 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 in using the electronic form, contact Wendy Muller. An unofficial Word version of the nomination form is posted on the 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 unofficial nomination form for additional information.

Next Steps

The SC is expected to appoint members to the team September 2017. Nominees will be notified shortly after they have been appointed.

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

For more information or assistance 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

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-002-2 – Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event		
Date Submitted:			
SAR Requester Information			
Name:	Darrel Richardson		
Organization:	NERC Staff		
Telephone:	609.613.1848	Email:	darrel.richardson@nerc.net
SAR Type (Check as many as applicable)			
☐ New Standard		☐ Withdrawal of Existing Standard	
☒ Revision to Existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
On January 19, 2017, FERC issued an order directing the ERO to develop modifications to standard BAL-002-2 to address their concerns regarding the 15-minute recovery period set forth in Requirement R1. In the order, FERC stated: “Accordingly, we direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require Balancing Authorities (BA) or Reserve Sharing Groups (RSG): (1) to notify the reliability coordinator of the conditions set forth in Requirement R1, Part 1.3.1 preventing it from complying with

SAR Information
the 15-minute ACE recovery period; and (2) to provide the reliability coordinator with its ACE recovery plan, including a target recovery time. NERC may also propose an equally efficient and effective alternative." Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event Reliability Standard, 158 FERC ¶ 61,030 at P 37 (2017) ("FERC Order"). *See also, id.*, at P 2 and PP 35-36.
Purpose or Goal (How does this request propose to address the problem described above?):
The primary goal of this SAR is to allow the standard drafting team (SDT) for Project 2017-06, Disturbance Control to modify standard BAL-002-2 to address the directives of the January 19, 2017 FERC Order, and to ensure consistency within the NERC body of Reliability Standards.
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
The objective of this SAR is to provide clear, unambiguous requirements to address the directives in the January 19, 2017 FERC Order regarding the recovery from a Balancing Contingency Event, or alternatively propose modifications that address the Commission concerns.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The SDT shall modify the standard, Violation Risk Factors, Violation Severity Levels, and implementation plan and shall work with compliance on an accompanying RSAW to address the FERC Order directives described above.
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.)
The SDTs execution of this SAR requires the SDT to address the FERC Order directives described above or alternatively propose modifications that address the Commission concerns in the FERC Order. This SAR will specifically address either (A) revising BAL-002-2 to require that BAs and RSGs: (1) notify the Reliability Coordinator that the BA or RSG cannot comply with the 15-minute ACE recovery period due to existence of the conditions as set forth in Requirement R1, Part 1.3.1; and (2) provide the Reliability Coordinator with an ACE recovery plan that includes a target recovery time; or (B) proposing an equally efficient and effective alternative.

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
None	

Related SARs	
SAR ID	Explanation
None	

Regional Variances	
Region	Explanation
ERCOT	None.
FRCC	None.
MRO	None.
NPCC	None.
RFC	None.

Regional Variances	
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 Board of Trustees.

Description of Current Draft

Completed Actions	Date
SAR posted for comment	06/20/17 – 07/20/17

Anticipated Actions	Date
45-day formal comment period with initial ballot	February 2018 through March 2018
10-day final ballot	April 2018
NERC Board (Board) adoption	May 2018

A. Introduction

1. **Title:** Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event
2. **Number:** BAL-002-3
3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.
4. **Applicability:**

    4.1. Responsible Entity

    4.1.1. Balancing Authority

    4.1.1.1. A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Reserve Sharing Group.

    4.1.2. Reserve Sharing Group

5. **Effective Date:** See the Implementation Plan for BAL-002-3.

B. Requirements and Measures

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity:

1.3.1 is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert Level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1. If Requirement R1 part 1.3 applies, then dated documentation that demonstrates compliance with Requirement R1 part 1.3 must also be provided.

R2. Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M2. Each Responsible Entity will have the following documentation to show compliance with Requirement R2:

- a dated Operating Process;
- evidence to indicate that the Operating Process has been reviewed and maintained annually; and,
- evidence such as Operating Plans or other operator documentation that demonstrate that the entity determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency are included in this process.

R3. Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration Period resets the beginning of the Contingency Event Recovery Period. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Responsible Entity will have documentation demonstrating its Contingency Reserve was restored within the Contingency Reserve Restoration Period, such as historical data, computer logs or operator logs.

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 Responsible Entity shall retain data or evidence to show compliance for the current year, plus three previous 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 Responsible Entity is found noncompliant, it shall keep information related to the noncompliance 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 Assessment Processes:

As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” 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.

1.4. Additional Compliance Information

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The Responsible Entity achieved less than 100% but at least 90% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period OR The Responsible Entity failed to use CR Form 1 to document a Reportable Balancing Contingency Event.	The Responsible Entity achieved less than 90% but at least 80% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 80% but at least 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.
R2.	The Responsible Entity developed and implemented an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to maintain	N/A	The Responsible Entity developed an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to implement the Operating Process.	The Responsible Entity failed to develop an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency.

	annually the Operating Process.			
R3.	The Responsible Entity restored less than 100% but at least 90% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 90% but at least 80% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 80% but at least 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

CR Form 1

BAL-002-3 Rationales

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	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata
1	September 9, 2010	Filed petition for revisions to BAL-002 Version 1 with the Commission	Revision
1	January 10, 2011	FERC letter ordered in Docket No. RD10-15-00 approving BAL-002-1	
1	April 1, 2012	Effective Date of BAL-002-1	
1a	November 7, 2012	Interpretation adopted by the NERC Board of Trustees	
1a	February 12, 2013	Interpretation submitted to FERC	
2	November 5, 2015	Adopted by NERC Board of Trustees	Complete revision
2	January 19, 2017	FERC Order approved BAL-002-2. Docket No. RM16-7-000	
2	October 2, 2017	FERC letter Order issued approving raising the VRF for Requirement R1 and R2 from Medium to High. Docket No. RD17-6-000.	

Standard Development Timeline

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NERC Board (Board) adoption	May 2018

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4. **Applicability:**

   4.1. Responsible Entity

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   4.1.1.1. A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Reserve Sharing Group.

   4.1.2. Reserve Sharing Group
5. **Effective Date:** See the Implementation Plan for BAL-002-3~~2~~.

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- is ~~a Balancing Authority~~ experiencing a Reliability Coordinator declared Energy Emergency Alert Level~~ or is a Reserve Sharing Group whose member, or members, are experiencing a Reliability Coordinator declared Energy Emergency Alert level~~, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
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D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document~~

CR Form 1

BAL-002-3 Rationales

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	February 14, 2006	Revised graph on page 3, “10 min.” to “Recovery time.” Removed fourth bullet.	Errata
1	September 9, 2010	Filed petition for revisions to BAL-002 Version 1 with the Commission	Revision
1	January 10, 2011	FERC letter ordered in Docket No. RD10-15-00 approving BAL-002-1	
1	April 1, 2012	Effective Date of BAL-002-1	
1a	November 7, 2012	Interpretation adopted by the NERC Board of Trustees	
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2	November 5, 2015	Adopted by NERC Board of Trustees	Complete revision
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Implementation Plan

Project 2017-06 Modifications to BAL-002-2

Requested Approvals

- BAL-002-3 Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

Requested Retirements

- BAL-002-2 Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

Applicable Entities

- Balancing Authority
- Reserve Sharing Group

Effective Date

The effective date for proposed Reliability Standard BAL-002-3 is provided below:

Where approval by an applicable governmental authority is required, Reliability Standard BAL-002-3 shall become effective the first day of the first calendar quarter that is six (6) calendar months after the effective date of the applicable governmental authority's order approving the standards and terms, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard BAL-002-3 shall become effective on the first day of the first calendar quarter that is six (6) calendar months after the date the standards and terms are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Current NERC Reliability Standards

The existing standard BAL-002-2 shall be retired immediately prior to the effective date of the proposed BAL-002-3 standard.

Unofficial Comment Form

Project 2017-06 Modifications to BAL-002-2

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2017-06 Modifications to BAL-002-2**. Comments must be submitted by **8 p.m. Eastern, Monday, May 7, 2018**.

Additional information is available on the project page. If you have questions, contact Principal Technical Advisor, Darrel Richardson (via email) or at (609) 613-1848.

Background

On January 19, 2017, FERC issued an order directing the ERO to develop modifications to standard BAL-002-2 to address their concerns regarding the 15-minute recovery period set forth in Requirement R1. In the order, FERC stated:

> "Accordingly, we direct NERC to develop modifications to Reliability Standard BAL-002-2, Requirement R1 to require Balancing Authorities (BA) or Reserve Sharing Groups (RSG): (1) to notify the reliability coordinator of the conditions set forth in Requirement R1, Part 1.3.1 preventing it from complying with the 15-minute ACE recovery period; and (2) to provide the reliability coordinator with its ACE recovery plan, including a target recovery time. NERC may also propose an equally efficient and effective alternative."

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

Questions

1. The SDT has modified Requirement R1 to address the Commission's concerns identified in FERC Order 835. Do you agree that the proposed modifications clearly state the intentions of the SAR? If not, please state your concerns and provide specific language on the proposed revision.

   ☐ Yes
   ☐ No

   Comments:

2. Do you have any other comments for drafting team consideration?

   ☐ Yes
   ☐ No

   Comments:

Rationales for BAL-002-3

February, 2018

Requirement R1

The Responsible Entity experiencing a Reportable Balancing Contingency Event shall:

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity:

1.3.1 is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that:

- is a experiencing a Reliability Coordinator declared Energy Emergency Alert Level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time.

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

Rationale R1

Requirement R1 reflects the operating principles first established by NERC Policy 1 (Generation Control and Performance). Its objective is to assure the Responsible Entity balances resources and demand and returns its Reporting Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes the amount of Contingency Reserve and recovery and restoration timeframes the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1 part 1.3.2 below) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to Demand while managing reliability. The SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

Commenters suggested a Quarterly Compliance similar to the current reports sent to NERC. The drafting team attempted to draft measurement language and VSL's for quarterly monitoring of compliance to R1. But the drafting team found that the VSL levels developed were likely to place smaller Balancing Authority's (BA) and Reserve Sharing Groups (RSG) in a severe violation regardless of the size of the failure. Therefore, the drafting team has not adopted a quarterly compliance calculation. Also, the proposed requirement and compliance process meets the directive in Paragraph 354 of Order 693.

The language in R1 part 1.3 does not specifically state under which EEA level the exclusion applies to reduce the need for consequent modifications of the BAL-002 standard. Thus, language in Requirement 1 Part 1.3.1 addresses both current and future EEA process. In addition, the drafting team has added language to R 1.3.1 clarifying that if a BA is experiencing an EEA event under which its contingency reserve has been activated, the RSG in which it resides would also be considered to be exempt from R1 compliance.

In addition, to address FERC Order No. 835, the drafting team has modified Requirement R1 Part 1.3.1 to clarify that the Responsible Entity, is the Balancing Authority (BA) notifying the Reliability Coordinator (RC) of the conditions set forth in Requirement R1, Part 1.3.1 in accordance with the Energy Emergency Alert (EEA) procedures. Under the Energy Emergency Alert procedures, the BA must inform the RC of the conditions and necessary requirements to meet reliability and the RC must approve of the information being provided before issuing an Energy Emergency Alert. Requirement R1 Part 1.3.1 requires the BA to provide additional information to the RC, allowing the RC to have a wide-area view of the state of the Bulk Electric System for possible future decisions concerning the System. It also provides for relief to a BA or RSG when reserves are being utilized under an EEA. These modifications keep the issues associated with Energy Emergencies within the Emergency Preparedness and Operations Standards, while allowing BAL-002-3 to compliment the process and clarify the narrow set of conditions where the BA and/or RSG is not subject to compliance to R1..

Requirement R2

Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability.

Rationale R2

R2 establishes the need to actively plan in the near term (e.g., day-ahead) for expected Reportable Balancing Contingency Events. This requirement is similar to the current standard which requires an entity to have available a level of contingency reserves equal to or greater than its Most Severe Single Contingency.

Requirement R3

Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration Period resets the beginning of the Contingency Event Recovery Period.

Rationale R3

This requirement is similar to the existing requirement that an entity that has experienced an event shall restore its Contingency Reserves within 105 minutes of the event. Note that if an entity is experiencing an EEA it may need to depend on potential availability (or make ready for potential curtailment) of its firm loads to restore Contingency Reserve. This is the reason for the changes to the definition of Contingency Reserve in the posting.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement
Reminder
Project 2017-06 Modifications to BAL-002-2

Initial Ballot and Non-binding Poll Open through May 7, 2018

Now Available

The initial ballot and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels for **BAL-002-3 Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event** are open through **8 p.m. Eastern, Monday, May 7, 2018**.

Balloting

Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here. If you experience difficulties navigating the SBS, contact Wendy Muller.

- *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 ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

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

For more information or assistance, contact Principal Technical Advisor, Darrel Richardson (via email), or at (609) 613-1848.

Standards Announcement

Project 2017-06 Modifications to BAL-002-2

Comment Period Open through May 7, 2018

Now Available

A 45-day formal comment period for **BAL-002-3 Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event**, is open through **8 p.m. Eastern, Monday, May 7, 2018**.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience difficulty navigating the SBS, contact Wendy Muller. 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.*

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Friday, April 20, 2018.** Registered Ballot Body members can join the ballot pools here.

Next Steps

An initial ballot and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **April 27 – May 7, 2018**.

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

For more information or assistance, contact Principal Technical Advisor, 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

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/133)
Ballot Name: 2017-06 Modifications to BAL-002-2 BAL-002-3 IN 1 ST
Voting Start Date: 4/27/2018 12:01:00 AM
Voting End Date: 5/8/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 189
Total Ballot Pool: 231
Quorum: 81.82
Weighted Segment Value: 69.46

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	54	1	28	0.8	7	0.2	0	11	8
Segment: 2	6	0.2	2	0.2	0	0	0	1	3
Segment: 3	50	1	19	0.655	10	0.345	0	10	11
Segment: 4	14	0.9	5	0.5	4	0.4	0	2	3
Segment: 5	54	1	25	0.676	12	0.324	0	9	8
Segment: 6	43	1	20	0.69	9	0.31	0	7	7
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	1	0	0	0	0	0	0	1	0
Segment: 9	1	0	0	0	0	0	0	1	0
Segment: 10	7	0.4	3	0.3	1	0.1	0	2	1

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
Totals:	231	5.5	102	3.821	43	1.679	0	44	42

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Jamie Monette		None	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson	Adrian Andreoiu	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Dairyland Power Cooperative	Renee Leidel		None	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Entergy - Entergy Services, Inc.	Oliver Burke		Abstain	N/A
1	Exelon	Chris Scanlon		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Negative	Comments Submitted
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	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Negative	Third-Party Comments
1	JEA	Ted Hobson	Joe McClung	Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
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		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		None	N/A
1	Manitoba Hydro	Mike Smith		Abstain	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Negative	Comments Submitted
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	Public Utility District No. 1 of Snohomish County	Long Duong		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	Shawn Abrams		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	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	Howell Scott		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Kevin Giles		Abstain	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula		None	N/A
2	ISO New England, Inc.	Michael Puscas	Joshua Eason	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		None	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Vivian Vo		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	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	CPS Energy	James Grimshaw		None	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	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		Affirmative	N/A
3	Exelon	John Bee		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
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		None	N/A
3	Lincoln Electric System	Jason Fortik		None	N/A
3	Los Angeles Department of Water and Power	Henry (Hank) Williams		None	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Abstain	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	Third-Party Comments
3	Ocala Utility Services	Randy Hahn		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Abstain	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Negative	Comments Submitted
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A
3	Rutherford EMC	Tom Haire		None	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		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Snohomish County PUD No. 1	Mark Oens		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		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Thomas Breene		Negative	Third-Party Comments
3	Westar Energy	Bo Jones		Abstain	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	American Public Power Association	Jack Cashin		Abstain	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City of Poplar Bluff	Neal Williams		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Abstain	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	Third-Party Comments
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		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.	Anthony Jankowski		Negative	Third-Party Comments
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Kelsi Rigby		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		Negative	Third-Party Comments
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Dominion - Dominion Resources, Inc.	Lou Oberski		None	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Exelon	Ruth Miller		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Third-Party Comments
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough	Brandon McCormick	Negative	Comments Submitted
5	Lakeland Electric	Jim Howard		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Donald Sievertson		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Abstain	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Abstain	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
5	NaturEner USA, LLC	Eric Smith		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Erick Barrios		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Third-Party Comments
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		None	N/A
5	Omaha Public Power District	Mahmood Safi		None	N/A
5	Orlando Utilities Commission	Richard Kinas		Negative	Comments Submitted
5	Platte River Power Authority	Tyson Archie		Abstain	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Negative	Comments Submitted
5	Public Utility District No. 1 of Chelan County	Haley Sousa		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		Affirmative	N/A
5	Sacramento Municipal Utility District	Susan Oto	Joe Tarantino	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Salt River Project	Kevin Nielsen		Affirmative	N/A
5	Santee Cooper	Tommy Curtis		Affirmative	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	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	Tennessee Valley Authority	M Lee Thomas		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Mark Stein		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Negative	Third-Party Comments
5	Westar Energy	Laura Cox		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Jonathan Aragon		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Black Hills Corporation	Eric Scherr		None	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
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Exelon	Becky Webb		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
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	Negative	Third-Party Comments
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		Abstain	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	Third-Party Comments
6	New York Power Authority	Shivaz Chopra	Shelly Dineen	Abstain	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		Negative	Third-Party Comments
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Comments Submitted
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		None	N/A
6	Public Utility District No. 1 of Chelan County	Davis Jelusich		Abstain	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	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Franklin Lu		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		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Hathaway		Negative	Third-Party Comments
6	Westar Energy	Megan Wagner		Abstain	N/A
6	Western Area Power Administration	Charles Faust		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
8	David Kiguel	David Kiguel		Abstain	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Abstain	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Abstain	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 231 of 231 entries

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BALLOT RESULTS

Ballot Name: 2017-06 Modifications to BAL-002-2 BAL-002-3 Non-binding Poll IN 1 NB
Voting Start Date: 4/27/2018 12:01:00 AM
Voting End Date: 5/8/2018 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 176
Total Ballot Pool: 220
Quorum: 80
Weighted Segment Value: 77.19

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	50	1	24	0.857	4	0.143	14	8
Segment: 2	6	0.2	2	0.2	0	0	1	3
Segment: 3	50	1	16	0.696	7	0.304	15	12
Segment: 4	14	0.7	5	0.5	2	0.2	3	4
Segment: 5	50	1	22	0.733	8	0.267	12	8
Segment: 6	40	1	15	0.75	5	0.25	13	7
Segment: 7	1	0	0	0	0	0	0	1
Segment: 8	1	0	0	0	0	0	1	0
Segment: 9	1	0	0	0	0	0	1	0
Segment: 10	7	0.4	4	0.4	0	0	2	1
Totals:	220	5.3	88	4.136	26	1.164	62	44

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Ameren - Ameren Services	Eric Scott		None	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson	Adrian Andreoiu	Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Dairyland Power Cooperative	Renee Leidel		None	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Abstain	N/A
1	Exelon	Chris Scanlon		None	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Negative	Comments Submitted
1	JEA	Ted Hobson	Joe McClung	Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
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		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		None	N/A
1	Manitoba Hydro	Mike Smith		Abstain	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	Comments Submitted
1	NorthWestern Energy	Belinda Tierney	Dori Quam	None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PSEG - Public Service Electric and Gas Co.	Joseph Smith		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Long Duong		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	Shawn Abrams		Abstain	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	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	Howell Scott		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Tracy Sliman		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Kevin Giles		Abstain	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula		None	N/A
2	ISO New England, Inc.	Michael Puscas	Joshua Eason	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry Blike		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Abstain	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		Affirmative	N/A
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	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	Comments Submitted
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	CPS Energy	James Grimshaw		None	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Exelon	John Bee		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	Comments Submitted
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	Comments Submitted
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		None	N/A
3	Lincoln Electric System	Jason Fortik		None	N/A
3	Los Angeles Department of Water and Power	Henry (Hank) Williams		None	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Abstain	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	Comments Submitted
3	Ocala Utility Services	Randy Hahn		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Abstain	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		None	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A
3	Rutherford EMC	Tom Haire		None	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	Robert Kondziolka		Affirmative	N/A
3	Santee Cooper	James Poston		Abstain	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Snohomish County PUD No. 1	Mark Oens		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		Abstain	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Negative	Comments Submitted
3	Westar Energy	Bo Jones		Abstain	N/A
3	Xcel Energy, Inc.	Michael Ibold		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		None	N/A
4	American Public Power Association	Jack Cashin		Abstain	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City of Poplar Bluff	Neal Williams		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	Comments Submitted
4	Georgia System Operations Corporation	Guy Andrews		Abstain	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		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.	Anthony Jankowski		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		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		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	Comments Submitted
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Dominion - Dominion Resources, Inc.	Lou Oberski		None	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Exelon	Ruth Miller		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	Comments Submitted
5	Great Plains Energy - Kansas City Power and Light Co.	Harold Wyble	Douglas Webb	Affirmative	N/A
5	Great River Energy	Preston Walsh		Negative	Comments Submitted
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough	Brandon McCormick	Negative	Comments Submitted
5	Lakeland Electric	Jim Howard		Negative	Comments Submitted
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Donald Sievertson		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Abstain	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Abstain	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
5	NaturEner USA, LLC	Eric Smith		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	New York Power Authority	Erick Barrios		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		None	N/A
5	Omaha Public Power District	Mahmood Safi		None	N/A
5	Orlando Utilities Commission	Richard Kinas		Negative	Comments Submitted
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		None	N/A
5	Public Utility District No. 1 of Chelan County	Haley Sousa		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		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	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	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	Tennessee Valley Authority	M Lee Thomas		Abstain	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	Westar Energy	Laura Cox		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Jonathan Aragon		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Black Hills Corporation	Eric Scherr		None	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		Abstain	N/A
6	Duke Energy	Greg Cecil		Affirmative	N/A
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
6	Exelon	Becky Webb		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	Comments Submitted
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	Comments Submitted
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	Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		Abstain	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	Comments Submitted
6	New York Power Authority	Shivaz Chopra	Shelly Dineen	Abstain	N/A
6	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Joe O'Brien		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		None	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		Abstain	N/A
6	Sacramento Municipal Utility District	Jamie Cutlip	Joe Tarantino	Affirmative	N/A
6	Salt River Project	Bobby Olsen		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	Snohomish County PUD No. 1	Franklin Lu		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		Abstain	N/A
6	Westar Energy	Megan Wagner		Abstain	N/A
6	Western Area Power Administration	Charles Faust		Affirmative	N/A
6	Xcel Energy, Inc.	Carrie Dixon		None	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
8	David Kiguel	David Kiguel		Abstain	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Abstain	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Affirmative	N/A
10	New York State Reliability Council	ALAN ADAMSON		Affirmative	N/A
10	Northeast Power Coordinating Council	Guy V. Zito		Abstain	N/A
10	ReliabilityFirst	Anthony Jablonski		Affirmative	N/A
10	SERC Reliability Corporation	Drew Slabaugh		None	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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Showing 1 to 220 of 220 entries

Standards Announcement

Project 2017-06 Modifications to BAL-002-2

Comment Period Open through May 7, 2018

Now Available

A 45-day formal comment period for **BAL-002-3 Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event**, is open through **8 p.m. Eastern, Monday, May 7, 2018**.

Commenting

Use the Standards Balloting and Commenting System (SBS) to submit comments. If you experience difficulty navigating the SBS, contact Wendy Muller. 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.*

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Friday, April 20, 2018.** Registered Ballot Body members can join the ballot pools here.

Next Steps

An initial ballot and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **April 27 – May 7, 2018**.

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

For more information or assistance, contact Principal Technical Advisor, 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

Comment Report

Project Name:	2017-06 Modifications to BAL-002-2 | BAL-002-3
Comment Period Start Date:	3/22/2018
Comment Period End Date:	5/8/2018
Associated Ballots:	2017-06 Modifications to BAL-002-2 BAL-002-3 IN 1 ST

There were 30 sets of responses, including comments from approximately 115 different people from approximately 87 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The SDT has modified Requirement R1 to address the Commission's concerns identified in FERC Order 835. Do you agree that the proposed modifications clearly state the intentions of the SAR?   If not, please state your concerns and provide specific language on the proposed revision.

2. 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
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
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

					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Bill Hutchison	Southern Illinois Power Cooperative	1	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
MRO	Cynthia Kneisl	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	5	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 Corporation	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,4,5	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO

					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					MIke Morrow	Midcontinent Independent System Operator	2	MRO
					Andy Fuhrman	Minnkota Power Cooperative	1	MRO
Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
Southern Company - Southern Company Services, Inc.	Katherine Prewitt	1		Southern Company	Scott Moore	Alabama Power Company	3	SERC
					Bill Shultz	Southern Company Generation	5	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
Tennessee Valley Authority	M Lee Thomas	5		Tennessee Valley Authority	Howell Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					M Lee Thomas	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC

Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion and NYISO	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

					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	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
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Don Schmit	Nebraska Public Power District	5	SPP RE
					Robert Hirchak	Cleco Corporation	6	SPP RE

PPL - Louisville Gas and Electric Co.	Shelby Wade	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Charlie Freibert	LG&E and KU Energy, LLC	3	SERC
					Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Dan Wilson	LG&E and KU Energy, LLC	5	SERC
					Linn Oelker	LG&E and KU Energy, LLC	6	SERC

1. The SDT has modified Requirement R1 to address the Commission's concerns identified in FERC Order 835. Do you agree that the proposed modifications clearly state the intentions of the SAR?   If not, please state your concerns and provide specific language on the proposed revision.

Cynthia Kneisl - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

While the SAR and the proposed changes address the stated FERC directive from one perspective, NERC is authorized to propose an equally effective alternative to achieve the reliability objective. We believe the approach in the draft standard could negatively impact reliability.

Our comments below outline issues with the standard and the direction it is taking. The change will distract operators from their primary tasks in order to develop and discuss a plan following a contingency during an Energy Emergency Alert (EEA).

The provisions being changed deal with exclusions to compliance. We believe the better path is for the drafting team to work with NERC (with input from the NERC OC) to create Implementation Guidance and a companion CMEP Practice Guide that outlines approaches for multi-contingent events, events > Most Severe Single Contingencies, and for ERO Compliance Staff to handle Reportable Balancing Contingency Events (RBCEs) during EEAs.

We also believe there is more to gain from a reliability perspective to pass these rare events through the Events Analysis process to create lessons-learned.

Finally, if the drafting team rejects our comments, we believe the change should be limited to: "Notified the RC that they have experienced a Reportable Balancing Contingency Event (RBCE) in cases where the BA expects recovery to take > 30 minutes and provided proposed actions and an expected recovery time."

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	

While the proposed changes appear to clearly state the intention of the SAR, certain parts appear to be redundant with some of the existing requirements while other parts seem unnecessary if an alternative means, such as an exception to compliance, is developed.

Firstly, Point (i) in the forth bullet under Part 1.3.1 is unnecessary:

1. **The first bullet under Part 1.3.1 implies that a BA's RC is already aware of the EEA declaration (since it makes that declaration itself!)**
2. **The RC is already notified of its BA's emergency condition via EOP-011, Requirement R2 (Part 2.2.1).**

Secondly, regarding Point (ii) in Part 1.3.1, a BA's priority under either an EEA or a capacity or energy emergency is to mitigate the emergency condition to return the BA Area to normal state. Developing and notifying its RC a plan to recover ACE under either condition should not be a priority as such a task may actually jeopardize reliability. A BA should be allowed time to manage its EEA and/or emergency. Only when such issues are duly addressed and the BA is out of EEA and/or emergency should it be required to notify its RC of an ACE recovery plan, including target recovery time, or the actions being undertaken to recover ACE.

We therefore urge the SDT to seek an alternative means (such as an exception to compliance) to meet the FERC directive on providing an ACE recovery plan, or to create a Part 1.4 that will require a BA to notify its RC of an ACE recovery plan, including target recovery time or its actions being undertaken to recover ACE, after it has recovered from an EEA or a capacity or energy emergency.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

: FMPA is concerned that the proposed modifications could potentially be a distraction for operators and negatively impact reliability. We agree with the following comments submitted by MRO:

While the SAR and the proposed changes address the stated FERC directive from one perspective, NERC is authorized to propose an equally effective alternative to achieve the reliability objective. We believe the approach in the draft standard could negatively impact reliability.

Our comments below outline issues with the standard and the direction it is taking. The change will distract operators from their primary tasks in order to develop and discuss a plan following a contingency during an Energy Emergency Alert (EEA).

The provisions being changed deal with exclusions to compliance. We believe the better path is for the drafting team to work with NERC (with input from the NERC OC) to create Implementation Guidance and a companion CMEP Practice Guide that outlines approaches for multi-contingent events, events > Most Severe Single Contingencies, and for ERO Compliance Staff to handle Reportable Balancing Contingency Events (RBCEs) during EEAs.

We also believe there is more to gain from a reliability perspective to pass these rare events through the Events Analysis process to create lessons-learned.

Finally, if the drafting team rejects our comments, we believe the change should be limited to: “Notified the RC that they have experienced a Reportable Balancing Contingency Event (RBCE) in cases where the BA expects recovery to take > 30 minutes and provided proposed actions and an expected recovery time.”

Likes 0	
Dislikes 0	

Response

Richard Kinas - Orlando Utilities Commission - 5

Answer	No
Document Name	

Comment

OUC is concerned that the proposed modifications could potentially be a distraction for operators and negatively impact reliability. We agree with the following comments submitted by MRO:

While the SAR and the proposed changes address the stated FERC directive from one perspective, NERC is authorized to propose an equally effective alternative to achieve the reliability objective. We believe the approach in the draft standard could negatively impact reliability.

Our comments below outline issues with the standard and the direction it is taking. The change will distract operators from their primary tasks in order to develop and discuss a plan following a contingency during an Energy Emergency Alert (EEA).

The provisions being changed deal with exclusions to compliance. We believe the better path is for the drafting team to work with NERC (with input from the NERC OC) to create Implementation Guidance and a companion CMEP Practice Guide that outlines approaches for multi-contingent events, events > Most Severe Single Contingencies, and for ERO Compliance Staff to handle Reportable Balancing Contingency Events (RBCEs) during EEAs.

We also believe there is more to gain from a reliability perspective to pass these rare events through the Events Analysis process to create lessons-learned.

Finally, if the drafting team rejects our comments, we believe the change should be limited to: “Notified the RC that they have experienced a Reportable Balancing Contingency Event (RBCE) in cases where the BA expects recovery to take > 30 minutes and provided proposed actions and an expected recovery time.”

Likes 0	
Dislikes 0	

Response

Richard Vine - California ISO - 2

Answer	No

Document Name	

Comment
While the SAR and the proposed changes address the stated FERC directive from one perspective, NERC is authorized to propose an equally effective alternative. We believe the approach in the draft standard could negatively impact reliability. Our comments below outline issues with the standard and the direction it is taking. The change will distract operators from their primary tasks in order to develop and discuss a plan following a contingency during an EEA. The provisions being changed deal with exclusions to compliance. We believe the better path is for the drafting team to work with NERC (with input from the NERC OC) to create a CMEP Practice Guide that outlines an approach for ERO Compliance Staff to handle RBCEs during these situations. We also believe there is more to gain from a reliability perspective to pass these rare events through the Events Analysis process to create lessons-learned. Finally, if the drafting team rejects our comments, we believe the change should be limited to: “Notified the RC that they have experienced a Reportable Balancing Contingency Event (RBCE) and provided an expected recovery time”.

Likes 0	
Dislikes 0	

Response
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority

Answer	No
Document Name	

Comment
We believe that the conditions set forth in the first requirement of the FERC order are already accomplished through the requirements in EOP-011 for declaring an EEA 3 and should not be restated here in BAL-002. A BA experiencing the conditions set forth in the first three bullets in R1.3.1 is by definition experiencing EEA 3 conditions and the required communication to the RC is satisfied through the request to declare an EEA 3. Restating them in this standard could lead to conflicts between the standards as they evolve over time. We are also concerned that the current language in the draft could cause a delay in recovery from an event as the contingent BA’s time is occupied creating a detailed level of audit evidence documenting the official recovery plan and recovery time estimate during the Recovery Period of the event and then communicating those to the RC. This would only serve to prolong the threat to the BES caused by the supply shortage which occurred as a result of the contingency.

Likes 0	
Dislikes 0	

Response
David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment	
Ameren believes that any Requirement for actions an entity is required to take when experiencing an RC declared EEA level belongs in EOP-011, Emergency Operations. **In lieu thereof, Ameren believes the following BAL-002-3 language would be an acceptable alternative to meet the intent and spirit of the FERC directive, until a revision of EOP-011-1 occurs as described below:** **In addition to the redline changes for R1.3 and R1.3.1, Ameren suggests adding the additional bullets as stated below:** **•provide updates to the ACE recovery plan, including target recovery time, to its Reliability Coordinator, during its communications with the RC as required in "Attachment 1-EOP-011-1 Energy Emergency Alerts"** **•and implements the ACE recovery plan when given an Operating Instruction to do so by its RC.**	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
TVA believes that the conditions set forth in the 1st requirement of the FERC order are already accomplished through the requirements in EOP-011 for declaring an EEA 3 and should not be restated here in BAL-002. A BA experiencing the conditions set forth in the first three bullets in R1.3.1 is by definition experiencing EEA 3 conditions and the required communication to the RC is satisfied through the request to declare an EEA 3. Restating them in this standard could lead to conflicts between the standards as they evolve over time. We are also concerned that the current language in the draft could cause a delay in recovery from an event as the contingent BA's time is occupied creating a detailed level of audit evidence documenting the official recovery plan and recovery time estimate during the Recovery Period of the event and then communicating those to the RC. This would only serve to prolong the threat to the BES caused by the supply shortage which occurred as a result of the contingency.	
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 and NYISO	
Answer	No
Document Name	
Comment	

While the proposed changes appear to clearly state the intention of the SAR, certain parts appear to be redundant with some of the existing requirements while other parts seem unnecessary if an alternative means, such as an exception to compliance, is developed.

Firstly, Point (i) in the forth bullet under Part 1.3.1 is unnecessary:

1. The first bullet under Part 1.3.1 implies that a BA's RC is already aware of the EEA declaration (since it makes that declaration itself!)
2. The RC is already notified of its BA's emergency condition via EOP-011, Requirement R2 (Part 2.2.1).

Secondly, regarding Point (ii) in Part 1.3.1, a BA's priority under either an EEA or a capacity or energy emergency is to mitigate the emergency condition to return the BA Area to normal state. Developing and notifying its RC a plan to recover ACE under either condition should not be a priority as such a task may actually jeopardize reliability. A BA should be allowed time to manage its EEA and/or emergency. Only when such issues are duly addressed and the BA is out of EEA and/or emergency should it be required to notify its RC of an ACE recovery plan, including target recovery time, or the actions being undertaken to recover ACE.

We therefore urge the SDT to seek an alternative means (such as an exception to compliance) to meet the FERC directive on providing an ACE recovery plan, or to create a Part 1.4 that will require a BA to notify its RC of an ACE recovery plan, including target recovery time or its actions being undertaken to recover ACE, after it has recovered from an EEA or a capacity or energy emergency.

Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	

1. We believe the proposed reference to "preceding two bullet points" should be clarified, as compliance with this requirement can be confusing. Very few NERC Reliability Requirements identify an action and then follow that with an exemption to the action based on a specific condition. The proposed changes are made to the exemption portion of the requirement, which already implies that compliance with Requirement R1 part 1.1 is unnecessary. The embedded dual condition within the proposed bullet should be split to provide clarity. One bullet

should identify the inhibitive reasoning provided to the RC from the distressed BA or RSG that is unable to restore its ACE to the appropriate Pre -Reporting Contingency Event ACE Value within t The second bullet should also identify that the
ACE recovery plan was provided to the RC.

2. The reference to “recovery time” should be replaced with the appropriate NERC Glossary Term, Contingency Event Recovery Period.

Likes 0	
Dislikes 0	

Response

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

N/A to BHC

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

BPA suggests rewording of “an ACE recovery plan” to “actions it will take to recover its ACE”. BPA believes this rewording will help R1 sound less like a defined term which will depend on or require additional documentation. BPA’s concern is that “an ACE recovery plan” will be assumed to be an additional document such as the Emergency Operating Plan.

Likes 0	
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment

SRP supports the proposed revisions.	
Likes 0	
Dislikes 0	
Response	
Yvonne McMackin - Public Utility District No. 2 of Grant County, Washington - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
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	

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
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	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Laura Nelson - IDACORP - Idaho Power Company - 1

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. - 6, Group Name Dominion

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Selene Willis - Edison International - Southern California Edison Company - 1,3,5,6	
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	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5 - FRCC	
Answer	
Document Name	
Comment	
N/a	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
The SDT may wish to clarify when the ACE recovery plan must be submitted for a BA to qualify for the exemption. The proposed BAL-002-3 R 1.3 now specifies that a BA may be exempt from BAL-002-3 R1.1 if it has "during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedure" notified the RC of conditions preventing it from responding and "provided the Reliability Coordinator with an ACE recovery plan, including target recovery time."	
Likes 0	

Dislikes 0	
Response	

2. Do you have any other comments for drafting team consideration?

Brian Van Gheem - ACES Power Marketing - 6, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We thank you for this opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern 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 and NYISO	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
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	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ozan Ferrin - Tacoma Public Utilities (Tacoma, WA) - 5	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5 - FRCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Yvonne McMackin - Public Utility District No. 2 of Grant County, Washington - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	

Comment	
TVA believes that given the amount of actions BA’s are required to make during a Reportable Disturbance, and the very short window of time allowed in the standard to successfully complete those actions, that the Standards should not put additional regulatory burden on the operators to create documentation and notifications during this window. This small amount of time should be dedicated to restoring the BES to a stable condition. It is also important to note that the contingent BA is still subject to the BAAL limit during a contingency any time the BES is threatened with a negative supply balance; therefore, the BA still has a compliance obligation to restore its balance anytime the interconnection is threatened even if the BA is not subject to compliance under BAL-002. Given the small amount of Contingency Reserves available to the BA in this situation and the degree of time urgency, the BA should make every effort to recover its imbalance and deploy all remaining Contingency Reserves in order to recover as much imbalance as possible. Only once those actions are completed should the BA focus on communicating the recovery plan and target recovery time to the RC, and this should not be required to be within the Recovery Period in order to be granted a waiver from compliance under BAL-002. The proposed revision should be based on BAL-002-2(i), which is the last approved and currently effective version.	
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 suggests that the drafting team provide clarity on the intent of the proposed language pertaining to Requirement R1 Part 1.3.1. The proposed language in BAL-002 (Part 1.3.1) is addressing entities that would be in an EEA 3 knowing that they wouldn’t return to an acceptable status in the required 15 minutes. Looking at EOP-011, any entity that is in an EEA 3 per Attachment 1, that entity would have to report their status to the Reliability Coordinator (RC) every hour. To our understanding, the entity being identified in BAL-002 (Part 1.3.1-which would be in an EEA 3 situation and would not be in compliance) could make their report in that same hour until they return to an acceptable status. We ask the drafting team to clarify whether there is connection between the required actions of these two standards. If the drafting team agrees with our understanding, we would suggest that the drafting team include some language discussing the connection of both standards in BAL-002-3. This would provide clarity on the expectations of entities that don’t recover in the required 15 minutes as well as being in an EEA 3 condition.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	

We believe that given the amount of actions BA's are required to make during a Reportable Disturbance, and the very short window of time allowed in the standard to successfully complete those actions, that the Standards should not put additional regulatory burden on the operators to create documentation and notifications during this window. This small amount of time should be dedicated to restoring the BES to a stable condition. It is also important to note that the contingent BA is still subject to the BAAL limit during a contingency any time the BES is threatened with a negative supply balance; therefore, the BA still has a compliance obligation to restore its balance anytime the interconnection is threatened even if the BA is not subject to compliance under BAL-002. Given the small amount of Contingency Reserves available to the BA in this situation and the degree of time urgency, the BA should make every effort to recover its imbalance and deploy all remaining Contingency Reserves in order to recover as much imbalance as possible. Only once those actions are completed should the BA focus on communicating the recovery plan and target recovery time to the RC, and this should not be required to be within the Recovery Period in order to be granted a waiver from compliance under BAL-002.

The proposed revision should be based on BAL-002-2(i), which is the last approved and currently effective version.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	Yes
Document Name	

Comment

Dominion Energy has a concern regarding the Technical Rationale document. It appears that SDT has transitioned the existing GTB document to a Technical Rationale document without completely addressing all of the compliance langugae contained in the document.

"Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1 part 1.3.2 below) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to Demand while managing reliability."

This first example states when an entity does not have to comply and the standard is not applicable. It is not intent, it is a statement that directly impacts compliance. While the latter section of the section does state what the intent of the SDT was when developing the language and, in isolation would be appropriate for the TR document, the former part of the statement is not appropriate for the TR document. Just because a statement is not a specific example of how to comply does not render it appropriate for the TR document.

"In addition, the drafting team has added language to R 1.3.1 clarifying that if a BA is experiencing an EEA event underwhich its contingency reserve has been activated, the RSG in which it resides would also be considered to be exempt from R1 compliance."

The second quotation also makes a specific compliance statement, exempting a specific entity from compliance of the Requirement. While not an 'example' that could be directly ported to an IG document, it is compliance language that is not appropriate for a TR document. As stated before, just because compliance language does not fit the definition of IG does not render it appropriate for TR.

"Under the Energy Emergency Alert procedures, the BA must inform the RC of the conditions and necessary requirements to meet reliability and the RC must approve of the information being provided before issuing an Energy Emergency Alert."

The third quotation is a statement that clearly states how to comply with the EEA process. Once again, while not specific IG that statement is not appropriate for a TR document.

Likes 0	

Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	

We have concerns related to the unintended reliability consequences associated with the proposed changes in BAL-002-3 regarding the development and discussion of plans with the Reliability Coordinator in real time to restore ACE following a contingency during capacity shortages.

One thing that seems to be overlooked is that both the BA and RC have obligations in other standards to take action if a BA's ACE is negatively impacting frequency or transmission limits.

The exclusion provisions in the current BAL-002-2 deal with situations where the BA has multiple problems (capacity emergency, previous contingencies or multiple contingencies). Under these situations the BA may likely need to perform dozens of tasks in a 15 minute period.

The role of the Reliability Coordinator is not to manage or approve the local actions taken by the Balancing Authority. The proposed changes would put two sets of hands on the wheel and delay action. This is the equivalent of asking the pilot upon the loss of an engine to map out actions and reach out to the air traffic controller to discuss the pilot's proposal.

The original Disturbance Control Standard (DCS) in Policy 1 had basically two requirements:

- Recover from large events less than or equal to MSSC in 15 minutes.
- Replenish your reserves in 90 minutes such that you can recover from subsequent events.

There was an expectation that the BA made best efforts to recover from larger events as demonstrated by the reporting form that included events > MSSC and which NERC has tracked over the years. The remainder of the original DCS just explained how the two requirements above were accomplished in the context of a Reserve Sharing Group as well as provided administrative information to support the standard.

We are layering complexity in this standard at the same time NERC has a major project to streamline and focus the standards. Reliability would be better served if the standard were simplified under the Standards Efficiency Review process to the following requirements:

- Recover from Reportable Balancing Contingency Events in 15 minutes.
- Replenish reserves within 90 minutes as demonstrated by successful recovery from subsequent Reportable Balancing Contingency Events.
- Make best efforts and report recovery performance for events > MSSC or when reserves are diminished due to other contingencies.

The redline change to the standard has the BA telling the RC something they both already know and also expects the BA during an emergency to specifically mention two bullets in the standard. It should also be noted that the requirement is basically duplicative of EOP-011 R2.

As mentioned earlier, BAs are still held to the Balancing Authority ACE Limit as well as IROL requirements no matter what the size of the event. NERC collects DCS performance data for its State of Reliability Report, to include events > MSSC. NERC's report shows that BA performance has been stellar. If problems develop in the future, new requirements can be implemented.

Likes 0	

Dislikes 0	
Response	
Richard Kinas - Orlando Utilities Commission - 5	
Answer	Yes
Document Name	
Comment	

OUC is concerned that proposed modifications could negatively impact reliability by causing additional actions for the sake of compliance. Additionally, there seems to be some redundancy with EOP-011-1 2.2.1 which states “Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;”. Having redundancy and overlap in the standards goes against the current Standards Efficiency Review effort that is underway. OUC agrees with the following comments submitted by MRO:

We have concerns related to the unintended reliability consequences associated with the proposed changes in BAL-002-3 regarding the development and discussion of plans with the Reliability Coordinator in real time to restore ACE following a contingency during capacity shortages.

One thing that seems to be overlooked is that both the BA and RC have obligations in other standards to take action if a BA’s ACE is negatively impacting frequency or transmission limits.

The exclusion provisions in the current BAL-002-2 deal with situations where the BA has multiple problems (capacity emergency, previous contingencies or multiple contingencies). The priorities of a Balancing Authority following multiple contingencies are to:

Assess the incoming alarms and determine the extent of the problem.

Prioritize actions depending on the location of the event, whether there is a frequency issue or what transmission is being negatively impacted.

Direct generators to load to correct ACE or to adjust (in coordination with the Transmission Operator) to manage flows.

Coordinate with its TOP, adjacent BAs, and request assistance from the RC as needed.

There can be dozens of actions taking place in a matter of 10-15 minutes.

The role of the Reliability Coordinator is not to manage or approve the local actions taken by the Balancing Authority. The proposed changes would put two sets of hands on the wheel and delay action. This is the equivalent of asking the pilot upon the loss of an engine to map out actions and reach out to the air traffic controller to discuss the pilot’s proposal.

The role of the RC is to assist the BA as needed and point out external issues the Balancing Authority might not see. Only if a BA is not taking action and there are likely adverse reliability impacts should the RC intervene.

The original Disturbance Control Standard (DCS) prior to 2007 had basically two requirements:

Recover from large events less than or equal to MSSC in 15 minutes.

Replenish your reserves in 90 minutes such that you can recover from subsequent events.

There was an expectation that the BA made best efforts to recover from larger events as demonstrated by the reporting form that included events > MSSC and which NERC has tracked over the years. The remainder of the original DCS just explained how the two requirements above were accomplished in the context of a Reserve Sharing Group as well as provided administrative information to support the standard.

While BAL-002-0 made the original DCS more complex, any operator could understand the objectives and explain how performance is demonstrated. The currently enforceable BAL-002-2 is so complex that we believe no two operators asked to explain compliance would come up with the same answer. Version 3 not only layers complexity in the compliance evaluation; it will distract operators from their primary tasks.

We are layering complexity in this standard at the same time NERC has a major project to streamline and focus the standards. Reliability would be better served if the standard were simplified under the Standards Efficiency Review process to the following requirements:

Recover from Reportable Balancing Contingency Events in 15 minutes.

Replenish reserves within 90 minutes as demonstrated by successful recovery from subsequent Reportable Balancing Contingency Events.

Make best efforts and report recovery performance for events > MSSC or when reserves are diminished due to other contingencies.

As mentioned earlier, BAs are still held to the Balancing Authority ACE Limit as well as IROL requirements no matter what the size of the event. NERC collects DCS performance data for its State of Reliability Report, to include events > MSSC. NERC's report shows that BA performance has been stellar. If problems develop in the future, new requirements can be implemented.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	Yes
Document Name	

Comment

FMPA is concerned that proposed modifications could negatively impact reliability by causing additional actions for the sake of compliance. Additionally, there seems to be some redundancy with EOP-011-1 2.2.1 which states "Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;". Having redundancy and overlap in the standards goes against the current Standards Efficiency Review effort that is underway. FMPA agrees with the following comments submitted by MRO:

We have concerns related to the unintended reliability consequences associated with the proposed changes in BAL-002-3 regarding the development and discussion of plans with the Reliability Coordinator in real time to restore ACE following a contingency during capacity shortages.

One thing that seems to be overlooked is that both the BA and RC have obligations in other standards to take action if a BA's ACE is negatively impacting frequency or transmission limits.

The exclusion provisions in the current BAL-002-2 deal with situations where the BA has multiple problems (capacity emergency, previous contingencies or multiple contingencies). The priorities of a Balancing Authority following multiple contingencies are to:

Assess the incoming alarms and determine the extent of the problem.

Prioritize actions depending on the location of the event, whether there is a frequency issue or what transmission is being negatively impacted.

Direct generators to load to correct ACE or to adjust (in coordination with the Transmission Operator) to manage flows.

Coordinate with its TOP, adjacent BAs, and request assistance from the RC as needed.

There can be dozens of actions taking place in a matter of 10-15 minutes.

The role of the Reliability Coordinator is not to manage or approve the local actions taken by the Balancing Authority. The proposed changes would put two sets of hands on the wheel and delay action. This is the equivalent of asking the pilot upon the loss of an engine to map out actions and reach out to the air traffic controller to discuss the pilot's proposal.

The role of the RC is to assist the BA as needed and point out external issues the Balancing Authority might not see. Only if a BA is not taking action and there are likely adverse reliability impacts should the RC intervene.

The original Disturbance Control Standard (DCS) prior to 2007 had basically two requirements:

{C}· Recover from large events less than or equal to MSSC in 15 minutes.

{C}· Replenish your reserves in 90 minutes such that you can recover from subsequent events.

There was an expectation that the BA made best efforts to recover from larger events as demonstrated by the reporting form that included events > MSSC and which NERC has tracked over the years. The remainder of the original DCS just explained how the two requirements above were accomplished in the context of a Reserve Sharing Group as well as provided administrative information to support the standard.

While BAL-002-0 made the original DCS more complex, any operator could understand the objectives and explain how performance is demonstrated. The currently enforceable BAL-002-2 is so complex that we believe no two operators asked to explain compliance would come up with the same answer. Version 3 not only layers complexity in the compliance evaluation; it will distract operators from their primary tasks.

We are layering complexity in this standard at the same time NERC has a major project to streamline and focus the standards. Reliability would be better served if the standard were simplified under the Standards Efficiency Review process to the following requirements:

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As mentioned earlier, BAs are still held to the Balancing Authority ACE Limit as well as IROL requirements no matter what the size of the event. NERC collects DCS performance data for its State of Reliability Report, to include events > MSSC. NERC's report shows that BA performance has been stellar. If problems develop in the future, new requirements can be implemented.

Likes 0	
Dislikes 0	

Response

Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer	Yes
Document Name	

Comment

PPL NERC Registered Affiliates suggests that NERC post a complete redline of Proposed Reliability Standard BAL-002-3 to ensure the industry is fully aware of the transition of the Supplemental Material to a Technical Rationale document. The Redline to Last Approved Version of Proposed Reliability Standard BAL-002-3 posted to the NERC project page on March 22, 2018 is not a complete redline as it does not show the removal of the "Supplemental Material" (also known as Technical Rationale), which is currently included in the effective version BAL-002-2(i).

Furthermore, the document entitled "Rationales for BAL-002-3" should be entitled "Technical Rationale for BAL-002-3" in accordance with the NERC Technical Rationale for Reliability Standards Policy, and a redline to the last version of this document approved by industry should also be posted.

Additionally, the document entitled "Rationales for BAL-002-3" seems to include implementation guidance as it states "Requirement R1 does not apply when…".

Likes 0	
Dislikes 0	

Response

Cynthia Kneisl - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

We have concerns related to the unintended reliability consequences associated with the proposed changes in BAL-002-3 regarding the development and discussion of plans with the Reliability Coordinator in real time to restore ACE following a contingency during capacity shortages.

One thing that seems to be overlooked is that both the BA and RC have obligations in other standards to take action if a BA's ACE is negatively impacting frequency or transmission limits.

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- Prioritize actions depending on the location of the event, whether there is a frequency issue or what transmission is being negatively impacted.
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The role of the RC is to assist the BA as needed and point out external issues the Balancing Authority might not see. Only if a BA is not taking action and there are likely adverse reliability impacts should the RC intervene.

The original Disturbance Control Standard (DCS) prior to 2007 had basically two requirements:

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While BAL-002-0 made the original DCS more complex, any operator could understand the objectives and explain how performance is demonstrated. The currently enforceable BAL-002-2 is so complex that we believe no two operators asked to explain compliance would come up with the same answer. Version 3 not only layers complexity in the compliance evaluation; it will distract operators from their primary tasks.

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Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	Yes
Document Name	

Comment

Since it is necessary for a Balancing Authority to be in the conditions described in the first three bullets and have communicated those conditions to their Reliability Coordinator in order to be declared in an EEA, it is not necessary to repeat those steps in the proposed language in the fourth bullet of 1.3.1. The resulting fourth bullet would then read "has provided the Reliability Coordinator with an ACE recovery plan, including target recovery time

Likes 0	
Dislikes 0	

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

It appears that this version needs some clean-up prior to the final version. Texas RE noticed the following:

- The grammatical structure of Requirement 1 Part 1.3 is unclear as to whether the bullets are just for the RSG or the BA as well.
- In the “Rationales” document there is a reference to changes in definition of Contingency Reserve “in the posting” but it does not specify which posting.
- Texas RE requests to see a draft updated CR Form 1 since it is an associated document in Section F of the standard. Will this form be housed with the related documents?

Likes 0	
Dislikes 0	
Response	

Consideration of Comments

Project Name:	2017-06 Modifications to BAL-002-2 | BAL-002-3
Comment Period Start Date:	3/22/2018
Comment Period End Date:	5/8/2018
Associated Ballot:	2017-06 Modifications to BAL-002-2 BAL-002-3 IN 1 ST

There were 30 sets of responses, including comments from approximately 115 different people from approximately 87 companies representing the 10 Industry Segments as shown in the table on the following pages.

The Standard Drafting Team (SDT) scope was to address FERC's (Commission) requirements as listed in Order No. 835. The Commission stated in Order No. 835 it was concerned with a Balancing Authority operating out-of-balance for an extended period of time and is "leaning on the system" by relying on external resources to meet its obligations. Therefore, the Commission directed NERC to develop modifications to BAL-002-2 Requirement 1 to require balancing authorities: (1) to notify the reliability coordinator of the conditions set forth in Requirement R1, Part 1.3.1 preventing it from complying with the 15-minute ACE recovery period; and (2) to provide the reliability coordinator with the ACE recovery plan, including a target recovery time. The SDT took careful consideration to assure that fulfillment of this requirement could occur during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures.

Requirement R1, Part 1.3 addresses qualifying for exemption from Requirement R1 Part 1.1 and all conditions listed in Requirement R1, Part 1.3.1 must be met in order to qualify for the exemption. One of the conditions, is the BA is experiencing a Reliability Coordinator declared Energy Emergency Alert (EEA) Level. When a BA is experiencing a declared Energy emergency Alert level, it is communicating with its RC the conditions and its expected time to recover, which is basically addressing when a BA is out-of-balance and is "leaning on the system". By requiring an ACE recovery plan, the BA is providing the RC its expected time to recover and would no longer experiencing an EEA.

The SDT did not believe providing an ACE recovery plan place an onerous requirement on the BA, since under an EEA it requires the BA to provide to the RC such information.

Finally, to restate Requirement R1, Part 1.3 addresses qualifying for exemption from Requirement R1 Part 1.1. Since all conditions of Requirement R1, Part 1.3.1 must be met in order to qualify for exemption, the SDT expects exemption to be very rare. However, for the Responsible Entity to qualify for exemption, it must meet all conditions:

the Responsible Entity: is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert Level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures: (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1 , and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time.

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 Senior Director, Standards and Education Howard Gugel (via email) or at (404) 446-9693.

Questions

1. **The SDT has modified Requirement R1 to address the Commission's concerns identified in FERC Order 835. Do you agree that the proposed modifications clearly state the intentions of the SAR? If not, please state your concerns and provide specific language on the proposed revision.**

2. **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
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Steven Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
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
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					John Shaver	Arizona Electric Power	1	WECC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Cooperative, Inc.		
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Bill Hutchison	Southern Illinois Power Cooperative	1	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
MRO	Cynthia Kneisl	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	5	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					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 Corporation	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,4,5	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					MIke Morrow	Midcontinent Independent System Operator	2	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Andy Fuhrman	Minnkota Power Cooperative	1	MRO
Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
Southern Company - Southern Company Services, Inc.	Katherine Prewitt	1		Southern Company	Scott Moore	Alabama Power Company	3	SERC
					Bill Shultz	Southern Company Generation	5	SERC
					Jennifer Sykes	Southern Company Generation	6	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						and Energy Marketing		
Tennessee Valley Authority	M Lee Thomas	5		Tennessee Valley Authority	Howell Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					M Lee Thomas	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion and NYISO	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					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
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					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
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					Don Schmit	Nebraska Public Power District	5	SPP RE
					Robert Hirchak	Cleco Corporation	6	SPP RE
PPL - Louisville Gas and Electric Co.	Shelby Wade	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Charlie Freibert	LG&E and KU Energy, LLC	3	SERC
					Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Dan Wilson	LG&E and KU Energy, LLC	5	SERC
					Linn Oelker	LG&E and KU Energy, LLC	6	SERC

1. ***The SDT has modified Requirement R1 to address the Commission's concerns identified in FERC Order 835. Do you agree that the proposed modifications clearly state the intentions of the SAR? If not, please state your concerns and provide specific language on the proposed revision.***	
Cynthia Kneisl - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
While the SAR and the proposed changes address the stated FERC directive from one perspective, NERC is authorized to propose an equally effective alternative to achieve the reliability objective. We believe the approach in the draft standard could negatively impact reliability. Our comments below outline issues with the standard and the direction it is taking. The change will distract operators from their primary tasks in order to develop and discuss a plan following a contingency during an Energy Emergency Alert (EEA). The provisions being changed deal with exclusions to compliance. We believe the better path is for the drafting team to work with NERC (with input from the NERC OC) to create Implementation Guidance and a companion CMEP Practice Guide that outlines approaches for multi-contingent events, events > Most Severe Single Contingencies, and for ERO Compliance Staff to handle Reportable Balancing Contingency Events (RBCEs) during EEAs. We also believe there is more to gain from a reliability perspective to pass these rare events through the Events Analysis process to create lessons-learned. Finally, if the drafting team rejects our comments, we believe the change should be limited to: "Notified the RC that they have experienced a Reportable Balancing Contingency Event (RBCE) in cases where the BA expects recovery to take > 30 minutes and provided proposed actions and an expected recovery time."	
Likes 0	

Dislikes 0	

Response

Thank you for your comment. Since we are dealing with an exemption to the standard, provisions associated with the exemption must be included within the standard. Therefore the SDT modified the standard in accordance with the FERC direction including FERC provisions.

With regards to your comment concerning event analysis the SDT agrees and believes that all EEA declarations are reported and analyzed by the event analysis group.

An entity must meet all of the specific conditions to qualify for the exemption, and the ACE recovery plan is only required for the exemption.

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

While the proposed changes appear to clearly state the intention of the SAR, certain parts appear to be redundant with some of the existing requirements while other parts seem unnecessary if an alternative means, such as an exception to compliance, is developed.

Firstly, Point (i) in the forth bullet under Part 1.3.1 is unnecessary:

1. **The first bullet under Part 1.3.1 implies that a BA's RC is already aware of the EEA declaration (since it makes that declaration itself!)**
2. **The RC is already notified of its BA's emergency condition via EOP-011, Requirement R2 (Part 2.2.1).**

Secondly, regarding Point (ii) in Part 1.3.1, a BA's priority under either an EEA or a capacity or energy emergency is to mitigate the emergency condition to return the BA Area to normal state. Developing and notifying its RC a plan to recover ACE under either condition should not be a priority as such a task may actually jeopardize reliability. A BA should be allowed time to manage its EEA

and/or emergency. Only when such issues are duly addressed and the BA is out of EEA and/or emergency should it be required to notify its RC of an ACE recovery plan, including target recovery time, or the actions being undertaken to recover ACE. **We therefore urge the SDT to seek an alternative means (such as an exception to compliance) to meet the FERC directive on providing an ACE recovery plan, or to create a Part 1.4 that will require a BA to notify its RC of an ACE recovery plan, including target recovery time or its actions being undertaken to recover ACE, after it has recovered from an EEA or a capacity or energy emergency.**	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. ACE recovery plans are just one provision associated with exemption. Since FERC directed us to include this provision in the standard, the BA must meet all provisions to obtain exemption to Requirement R1. It's up to the BA to provide the ACE recovery plan to qualify for the exemption.	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	No
Document Name	
Comment	
: FMPA is concerned that the proposed modifications could potentially be a distraction for operators and negatively impact reliability. We agree with the following comments submitted by MRO: While the SAR and the proposed changes address the stated FERC directive from one perspective, NERC is authorized to propose an equally effective alternative to achieve the reliability objective. We believe the approach in the draft standard could negatively impact reliability.	

Our comments below outline issues with the standard and the direction it is taking. The change will distract operators from their primary tasks in order to develop and discuss a plan following a contingency during an Energy Emergency Alert (EEA). The provisions being changed deal with exclusions to compliance. We believe the better path is for the drafting team to work with NERC (with input from the NERC OC) to create Implementation Guidance and a companion CMEP Practice Guide that outlines approaches for multi-contingent events, events > Most Severe Single Contingencies, and for ERO Compliance Staff to handle Reportable Balancing Contingency Events (RBCEs) during EEAs. We also believe there is more to gain from a reliability perspective to pass these rare events through the Events Analysis process to create lessons-learned. Finally, if the drafting team rejects our comments, we believe the change should be limited to: "Notified the RC that they have experienced a Reportable Balancing Contingency Event (RBCE) in cases where the BA expects recovery to take > 30 minutes and provided proposed actions and an expected recovery time."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Since we are dealing with an exemption to the standard, provisions associated with the exemption must be included within the standard. Therefore the SDT modified the standard in accordance with the FERC direction including FERC provisions. With regards to your comment concerning event analysis, the SDT agrees and believes that all EEA declarations are reported and analyzed by the event analysis group. An entity must meet all of the specific conditions to qualify for the exemption, and the ACE recovery plan is only required for the exemption.	
Richard Kinas - Orlando Utilities Commission - 5	
Answer	No
Document Name	

Comment	
OUC is concerned that the proposed modifications could potentially be a distraction for operators and negatively impact reliability. We agree with the following comments submitted by MRO: While the SAR and the proposed changes address the stated FERC directive from one perspective, NERC is authorized to propose an equally effective alternative to achieve the reliability objective. We believe the approach in the draft standard could negatively impact reliability. Our comments below outline issues with the standard and the direction it is taking. The change will distract operators from their primary tasks in order to develop and discuss a plan following a contingency during an Energy Emergency Alert (EEA). The provisions being changed deal with exclusions to compliance. We believe the better path is for the drafting team to work with NERC (with input from the NERC OC) to create Implementation Guidance and a companion CMEP Practice Guide that outlines approaches for multi-contingent events, events > Most Severe Single Contingencies, and for ERO Compliance Staff to handle Reportable Balancing Contingency Events (RBCEs) during EEAs. We also believe there is more to gain from a reliability perspective to pass these rare events through the Events Analysis process to create lessons-learned. Finally, if the drafting team rejects our comments, we believe the change should be limited to: "Notified the RC that they have experienced a Reportable Balancing Contingency Event (RBCE) in cases where the BA expects recovery to take > 30 minutes and provided proposed actions and an expected recovery time."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Since we are dealing with an exemption to the standard, provisions associated with the exemption must be included within the standard. Therefore the SDT modified the standard in accordance with the FERC direction including FERC provisions.	

With regards to your comment concerning event analysis, the SDT agrees and believes that all EEA declarations are reported and analyzed by the event analysis group. An entity must meet all of the specific conditions to qualify for the exemption, and the ACE recovery plan is only required for the exemption.	
Richard Vine - California ISO - 2	
Answer	No
Document Name	
Comment	
While the SAR and the proposed changes address the stated FERC directive from one perspective, NERC is authorized to propose an equally effective alternative. We believe the approach in the draft standard could negatively impact reliability. Our comments below outline issues with the standard and the direction it is taking. The change will distract operators from their primary tasks in order to develop and discuss a plan following a contingency during an EEA. The provisions being changed deal with exclusions to compliance. We believe the better path is for the drafting team to work with NERC (with input from the NERC OC) to create a CMEP Practice Guide that outlines an approach for ERO Compliance Staff to handle RBCEs during these situations. We also believe there is more to gain from a reliability perspective to pass these rare events through the Events Analysis process to create lessons-learned. Finally, if the drafting team rejects our comments, we believe the change should be limited to: “Notified the RC that they have experienced a Reportable Balancing Contingency Event (RBCE) and provided an expected recovery time”.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Since we are dealing with an exemption to the standard, provisions associated with the exemption must be included within the standard. Therefore the SDT modified the standard in accordance with the FERC direction including FERC provisions. With regards to your comment concerning event analysis, the SDT agrees and believes that all EEA declarations are reported and analyzed by the event analysis group. An entity must meet all of the specific conditions to qualify for the exemption, and the ACE recovery plan is only required for the exemption.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
We believe that the conditions set forth in the first requirement of the FERC order are already accomplished through the requirements in EOP-011 for declaring an EEA 3 and should not be restated here in BAL-002. A BA experiencing the conditions set forth in the first three bullets in R1.3.1 is by definition experiencing EEA 3 conditions and the required communication to the RC is satisfied through the request to declare an EEA 3. Restating them in this standard could lead to conflicts between the standards as they evolve over time. We are also concerned that the current language in the draft could cause a delay in recovery from an event as the contingent BA's time is occupied creating a detailed level of audit evidence documenting the official recovery plan and recovery time estimate during the Recovery Period of the event and then communicating those to the RC. This would only serve to prolong the threat to the BES caused by the supply shortage which occurred as a result of the contingency.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC directed the SDT to include this provision as one of the conditions for exemption. The SDT took extreme care to assure we referenced the provisions within the Energy Emergency Alert procedures.	

David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	

Ameren believes that any Requirement for actions an entity is required to take when experiencing an RC declared EEA level belongs in EOP-011, Emergency Operations.

In lieu thereof, Ameren believes the following BAL-002-3 language would be an acceptable alternative to meet the intent and spirit of the FERC directive, until a revision of EOP-011-1 occurs as described below:

In addition to the redline changes for R1.3 and R1.3.1, Ameren suggests adding the additional bullets as stated below:

•provide updates to the ACE recovery plan, including target recovery time, to its Reliability Coordinator, during its communications with the RC as required in "Attachment 1-EOP-011-1 Energy Emergency Alerts"

•and implements the ACE recovery plan when given an Operating Instruction to do so by its RC.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT scope was associated with only the FERC Order associated with BAL-002. This SDT is not able to change the EEA procedure which would require a new or revised SAR.

ACE recovery plans are just one provision associated with exemption. Since FERC directed us to include this provision in the standard, the BA must meet all provisions to obtain exemption to Requirement R1. It’s up to the BA to provide the ACE recovery plan to qualify for the exemption.

M Lee Thomas - Tennessee Valley Authority - 5, Group Name Tennessee Valley Authority	
Answer	No

Document Name	
Comment	
TVA believes that the conditions set forth in the 1st requirement of the FERC order are already accomplished through the requirements in EOP-011 for declaring an EEA 3 and should not be restated here in BAL-002. A BA experiencing the conditions set forth in the first three bullets in R1.3.1 is by definition experiencing EEA 3 conditions and the required communication to the RC is satisfied through the request to declare an EEA 3. Restating them in this standard could lead to conflicts between the standards as they evolve over time. We are also concerned that the current language in the draft could cause a delay in recovery from an event as the contingent BA's time is occupied creating a detailed level of audit evidence documenting the official recovery plan and recovery time estimate during the Recovery Period of the event and then communicating those to the RC. This would only serve to prolong the threat to the BES caused by the supply shortage which occurred as a result of the contingency.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. FERC directed the SDT to include this provision as one of the conditions for exemption. The SDT took extreme care to assure we referenced the provisions within the Energy Emergency Alert procedures.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and NYISO	
Answer	No
Document Name	
Comment	
While the proposed changes appear to clearly state the intention of the SAR, certain parts appear to be redundant with some of the existing requirements while other parts seem unnecessary if an alternative means, such as an exception to compliance, is developed. Firstly, Point (i) in the forth bullet under Part 1.3.1 is unnecessary:	

1. The first bullet under Part 1.3.1 implies that a BA's RC is already aware of the EEA declaration (since it makes that declaration itself!)
2. The RC is already notified of its BA's emergency condition via EOP-011, Requirement R2 (Part 2.2.1).

Secondly, regarding Point (ii) in Part 1.3.1, a BA's priority under either an EEA or a capacity or energy emergency is to mitigate the emergency condition to return the BA Area to normal state. Developing and notifying its RC a plan to recover ACE under either condition should not be a priority as such a task may actually jeopardize reliability. A BA should be allowed time to manage its EEA and/or emergency. Only when such issues are duly addressed and the BA is out of EEA and/or emergency should it be required to notify its RC of an ACE recovery plan, including target recovery time, or the actions being undertaken to recover ACE.

We therefore urge the SDT to seek an alternative means (such as an exception to compliance) to meet the FERC directive on providing an ACE recovery plan, or to create a Part 1.4 that will require a BA to notify its RC of an ACE recovery plan, including target recovery time or its actions being undertaken to recover ACE, after it has recovered from an EEA or a capacity or energy emergency.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. ACE recovery plans are just one provision associated with exemption. Since FERC directed us to include this provision in the standard, the BA must meet all provisions to obtain exemption to Requirement R1. It's up to the BA to provide the ACE recovery plan to qualify for the exemption.

FERC directed the SDT to include this provision as one of the conditions for exemption. The SDT took extreme care to assure we referenced the provisions within the Energy Emergency Alert procedures.

Brian Van Gheem - ACES Power Marketing - 6, Group Name ACES Standards Collaborators

Answer	No
Document Name	

Comment	
1. We believe the proposed reference to “preceding two bullet points” should be clarified, as compliance with this requirement can be confusing. Very few NERC Reliability Requirements identify an action and then follow that with an exemption to the action based on a specific condition. The proposed changes are made to the exemption portion of the requirement, which already implies that compliance with Requirement R1 part 1.1 is unnecessary. The embedded dual condition within the proposed bullet should be split to provide clarity. One bullet should identify the inhibitive reasoning provided to the RC from the distressed BA or RSG that is unable to restore its ACE to the appropriate Pre-Reporting Contingency Event ACE Value within the Contingency Event Recovery Period. The second bullet should also identify that the ACE recovery plan was provided to the RC. 2. The reference to “recovery time” should be replaced with the appropriate NERC Glossary Term, Contingency Event Recovery Period.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. An entity must meet all of the specified conditions to qualify for the exemption, and the ACE recovery plan is only required for the exemption. With respect to your suggestion to split the fourth bullet, the SDT believes the condition as written must be a single bullet to maintain continuity within the bullet. Recovery time is an undefined term when dealing with the exemption and is variable when dealing with individual ACE recovery plans.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
N/A to BHC	

Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA suggests rewording of “an ACE recovery plan” to “actions it will take to recover its ACE”. BPA believes this rewording will help R1 sound less like a defined term which will depend on or require additional documentation. BPA’s concern is that “an ACE recovery plan” will be assumed to be an additional document such as the Emergency Operating Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment. The SDT took the wording directly from the FERC order.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP supports the proposed revisions.	
Likes 0	

Dislikes 0	
Response	
Thank you for your affirmative response and clarifying comment.	
Yvonne McMackin - Public Utility District No. 2 of Grant County, Washington - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
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	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
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	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
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. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 1,3,5,6	
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	
Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5 - FRCC	
Answer	
Document Name	
Comment	
N/a	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
The SDT may wish to clarify when the ACE recovery plan must be submitted for a BA to qualify for the exemption. The proposed BAL-002-3 R 1.3 now specifies that a BA may be exempt from BAL-002-3 R1.1 if it has "during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedure" notified the RC of conditions preventing it from responding and "provided the Reliability Coordinator with an ACE recovery plan, including target recovery time."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes that the entire recovery time frame is the period in which the BA is to notify the RC of its ACE recovery plan. During your discussions with the RC to declare an EEA the BA must provide all information associated with the	

emergency including the estimated period of the potential EEA and must update the RC hourly or upon a change of EEA status until the EEA is terminated. Part of the discussion with the RC to qualify for the exemption under BAL-002 will include your ACE recovery plan and the target recovery time. An entity must meet all of the specified conditions to qualify for the exemption, and the ACE recovery plan is only required for the exemption.

2. ***Do you have any other comments for drafting team consideration?***	
Brian Van Gheem - ACES Power Marketing - 6, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We thank you for this opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	

Katherine Prewitt - Southern Company - Southern Company Services, Inc. - 1, Group Name Southern 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 and NYISO	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Center - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	

Answer	No
Document Name	
Comment	
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	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Ozan Ferrin - Tacoma Public Utilities (Tacoma, WA) - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5 - FRCC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Yvonne McMackin - Public Utility District No. 2 of Grant County, Washington - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	

Comment	
TVA believes that given the amount of actions BA's are required to make during a Reportable Disturbance, and the very short window of time allowed in the standard to successfully complete those actions, that the Standards should not put additional regulatory burden on the operators to create documentation and notifications during this window. This small amount of time should be dedicated to restoring the BES to a stable condition. It is also important to note that the contingent BA is still subject to the BAAL limit during a contingency any time the BES is threatened with a negative supply balance; therefore, the BA still has a compliance obligation to restore its balance anytime the interconnection is threatened even if the BA is not subject to compliance under BAL-002. Given the small amount of Contingency Reserves available to the BA in this situation and the degree of time urgency, the BA should make every effort to recover its imbalance and deploy all remaining Contingency Reserves in order to recover as much imbalance as possible. Only once those actions are completed should the BA focus on communicating the recovery plan and target recovery time to the RC, and this should not be required to be within the Recovery Period in order to be granted a waiver from compliance under BAL-002. The proposed revision should be based on BAL-002-2(i), which is the last approved and currently effective version.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. ACE recovery plans are just one provision associated with exemption. Since FERC directed us to include this provision in the standard, the BA must meet all provisions to obtain exemption to Requirement R1. It's up to the BA to provide the ACE recovery plan to qualify for the exemption.	
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 suggests that the drafting team provide clarity on the intent of the proposed language pertaining to Requirement R1 Part 1.3.1. The proposed language in BAL-002 (Part 1.3.1) is addressing entities that would be in an EEA 3 knowing that	

they wouldn't return to an acceptable status in the required 15 minutes. Looking at EOP-011, any entity that is in an EEA 3 per Attachment 1, that entity would have to report their status to the Reliability Coordinator (RC) every hour. To our understanding, the entity being identified in BAL-002 (Part 1.3.1-which would be in an EEA 3 situation and would not be in compliance) could make their report in that same hour until they return to an acceptable status. We ask the drafting team to clarify whether there is connection between the required actions of these two standards. If the drafting team agrees with our understanding, we would suggest that the drafting team include some language discussing the connection of both standards in BAL-002-3. This would provide clarity on the expectations of entities that don't recover in the required 15 minutes as well as being in an EEA 3 condition.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. ACE recovery plans are just one provision associated with exemption. Since FERC directed us to include this provision in the standard, the BA must meet all provisions to obtain exemption to Requirement R1. It's up to the BA to provide the ACE recovery plan to qualify for the exemption. The SDT took extreme care to assure we referenced the provisions within the Energy Emergency Alert procedures.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	Yes
Document Name	
Comment	
We believe that given the amount of actions BA's are required to make during a Reportable Disturbance, and the very short window of time allowed in the standard to successfully complete those actions, that the Standards should not put additional regulatory burden on the operators to create documentation and notifications during this window. This small amount of time should be dedicated to restoring the BES to a stable condition. It is also important to note that the contingent BA is still subject to the BAAL limit during a contingency any time the BES is threatened with a negative supply balance; therefore, the BA still has a compliance obligation to restore its balance anytime the interconnection is threatened even if the BA is not subject to compliance under BAL-002. Given the small amount of Contingency Reserves available to the BA in this situation and the degree of time urgency, the BA should make every effort to recover its	

imbalance and deploy all remaining Contingency Reserves in order to recover as much imbalance as possible. Only once those actions are completed should the BA focus on communicating the recovery plan and target recovery time to the RC, and this should not be required to be within the Recovery Period in order to be granted a waiver from compliance under BAL-002. The proposed revision should be based on BAL-002-2(i), which is the last approved and currently effective version.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. ACE recovery plans are just one provision associated with exemption. Since FERC directed us to include this provision in the standard, the BA must meet all provisions to obtain exemption to Requirement R1. It's up to the BA to provide the ACE recovery plan to qualify for the exemption. The SDT took extreme care to assure we referenced the provisions within the Energy Emergency Alert procedures.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Dominion Energy has a concern regarding the Technical Rationale document. It appears that SDT has transitioned the existing GTB document to a Technical Rationale document without completely addressing all of the compliance langugae contained in the document. "Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1 part 1.3.2 below) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to Demand while managing reliability." This first example states when an entity does not have to comply and the standard is not applicable. It is not intent, it is a statement that directly impacts compliance. While the latter section of the section does state what the intent of the SDT was when developing the	

language and, in isolation would be appropriate for the TR document, the former part of the statement is not appropriate for the TR document. Just because a statement is not a specific example of how to comply does not render it appropriate for the TR document.

"In addition, the drafting team has added language to R 1.3.1 clarifying that if a BA is experiencing an EEA event underwhich its contingency reserve has been activated, the RSG in which it resides would also be considered to be exempt from R1 compliance."

The second quotation also makes a specific compliance statement, exempting a specific entity from compliance of the Requirement. While not an 'example' that could be directly ported to an IG document, it is compliance language that is not appropriate for a TR document. As stated before, just because compliance language does not fit the definition of IG does not render it appropriate for TR.

"Under the Energy Emergency Alert procedures, the BA must inform the RC of the conditions and necessary requirements to meet reliability and the RC must approve of the information being provided before issuing an Energy Emergency Alert."

The third quotation is a statement that clearly states how to comply with the EEA process. Once again, while not specific IG that statement is not appropriate for a TR document.

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT will consider your comments and make associated modifications, if necessary.	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	

We have concerns related to the unintended reliability consequences associated with the proposed changes in BAL-002-3 regarding the development and discussion of plans with the Reliability Coordinator in real time to restore ACE following a contingency during capacity shortages.

One thing that seems to be overlooked is that both the BA and RC have obligations in other standards to take action if a BA's ACE is negatively impacting frequency or transmission limits.

The exclusion provisions in the current BAL-002-2 deal with situations where the BA has multiple problems (capacity emergency, previous contingencies or multiple contingencies). Under these situations the BA may likely need to perform dozens of tasks in a 15 minute period.

The role of the Reliability Coordinator is not to manage or approve the local actions taken by the Balancing Authority. The proposed changes would put two sets of hands on the wheel and delay action. This is the equivalent of asking the pilot upon the loss of an engine to map out actions and reach out to the air traffic controller to discuss the pilot's proposal.

The original Disturbance Control Standard (DCS) in Policy 1 had basically two requirements:

- Recover from large events less than or equal to MSSC in 15 minutes.
- Replenish your reserves in 90 minutes such that you can recover from subsequent events.

There was an expectation that the BA made best efforts to recover from larger events as demonstrated by the reporting form that included events > MSSC and which NERC has tracked over the years. The remainder of the original DCS just explained how the two requirements above were accomplished in the context of a Reserve Sharing Group as well as provided administrative information to support the standard.

We are layering complexity in this standard at the same time NERC has a major project to streamline and focus the standards. Reliability would be better served if the standard were simplified under the Standards Efficiency Review process to the following requirements:

- Recover from Reportable Balancing Contingency Events in 15 minutes.
- Replenish reserves within 90 minutes as demonstrated by successful recovery from subsequent Reportable Balancing Contingency Events.
- Make best efforts and report recovery performance for events > MSSC or when reserves are diminished due to other contingencies.

The redline change to the standard has the BA telling the RC something they both already know and also expects the BA during an emergency to specifically mention two bullets in the standard. It should also be noted that the requirement is basically duplicative of EOP-011 R2.

As mentioned earlier, BAs are still held to the Balancing Authority ACE Limit as well as IROL requirements no matter what the size of the event. NERC collects DCS performance data for its State of Reliability Report, to include events > MSSC. NERC's report shows that BA performance has been stellar. If problems develop in the future, new requirements can be implemented.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. ACE recovery plans are just one provision associated with an exemption. Since FERC directed us to include this provision in the standard, the BA must meet all provisions to obtain exemption to Requirement R1. It's up to the BA to provide the ACE recovery plan to qualify for the exemption.

All other standards are still applicable such as BAL-001, IROLs, etc. and it is up to the BA to address these other standards with the RC.

Richard Kinas - Orlando Utilities Commission - 5

Answer	Yes
Document Name	

Comment

OUC is concerned that proposed modifications could negatively impact reliability by causing additional actions for the sake of compliance. Additionally, there seems to be some redundancy with EOP-011-1 2.2.1 which states "Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;". Having redundancy and overlap in the standards goes against the current Standards Efficiency Review effort that is underway. OUC agrees with the following comments submitted by MRO:

We have concerns related to the unintended reliability consequences associated with the proposed changes in BAL-002-3 regarding the development and discussion of plans with the Reliability Coordinator in real time to restore ACE following a contingency during capacity shortages.

One thing that seems to be overlooked is that both the BA and RC have obligations in other standards to take action if a BA's ACE is negatively impacting frequency or transmission limits.

The exclusion provisions in the current BAL-002-2 deal with situations where the BA has multiple problems (capacity emergency, previous contingencies or multiple contingencies). The priorities of a Balancing Authority following multiple contingencies are to:

Assess the incoming alarms and determine the extent of the problem.

Prioritize actions depending on the location of the event, whether there is a frequency issue or what transmission is being negatively impacted.

Direct generators to load to correct ACE or to adjust (in coordination with the Transmission Operator) to manage flows.

Coordinate with its TOP, adjacent BAs, and request assistance from the RC as needed.

There can be dozens of actions taking place in a matter of 10-15 minutes.

The role of the Reliability Coordinator is not to manage or approve the local actions taken by the Balancing Authority. The proposed changes would put two sets of hands on the wheel and delay action. This is the equivalent of asking the pilot upon the loss of an engine to map out actions and reach out to the air traffic controller to discuss the pilot's proposal.

The role of the RC is to assist the BA as needed and point out external issues the Balancing Authority might not see. Only if a BA is not taking action and there are likely adverse reliability impacts should the RC intervene.

The original Disturbance Control Standard (DCS) prior to 2007 had basically two requirements:

Recover from large events less than or equal to MSSC in 15 minutes.

Replenish your reserves in 90 minutes such that you can recover from subsequent events.

There was an expectation that the BA made best efforts to recover from larger events as demonstrated by the reporting form that included events > MSSC and which NERC has tracked over the years. The remainder of the original DCS just explained how the two requirements above were accomplished in the context of a Reserve Sharing Group as well as provided administrative information to support the standard.

While BAL-002-0 made the original DCS more complex, any operator could understand the objectives and explain how performance is demonstrated. The currently enforceable BAL-002-2 is so complex that we believe no two operators asked to explain compliance would come up with the same answer. Version 3 not only layers complexity in the compliance evaluation; it will distract operators from their primary tasks.

We are layering complexity in this standard at the same time NERC has a major project to streamline and focus the standards. Reliability would be better served if the standard were simplified under the Standards Efficiency Review process to the following requirements:

Recover from Reportable Balancing Contingency Events in 15 minutes.

Replenish reserves within 90 minutes as demonstrated by successful recovery from subsequent Reportable Balancing Contingency Events.

Make best efforts and report recovery performance for events > MSSC or when reserves are diminished due to other contingencies.

As mentioned earlier, BAs are still held to the Balancing Authority ACE Limit as well as IROL requirements no matter what the size of the event. NERC collects DCS performance data for its State of Reliability Report, to include events > MSSC. NERC's report shows that BA performance has been stellar. If problems develop in the future, new requirements can be implemented.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. ACE recovery plans are just one provision associated with an exemption. Since FERC directed us to include this provision in the standard, the BA must meet all provisions to obtain exemption to Requirement R1. It's up to the BA to provide the ACE recovery plan to qualify for the exemption.

All other standards are still applicable such as BAL-001, IROLs, etc. and it is up to the BA to address these other standards with the RC.

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; David Owens, Gainesville Regional Utilities, 3, 1, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Mike Blough, Kissimmee Utility Authority, 5, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	

FMPA is concerned that proposed modifications could negatively impact reliability by causing additional actions for the sake of compliance. Additionally, there seems to be some redundancy with EOP-011-1 2.2.1 which states “Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;”. Having redundancy and overlap in the standards goes against the current Standards Efficiency Review effort that is underway. FMPA agrees with the following comments submitted by MRO:

We have concerns related to the unintended reliability consequences associated with the proposed changes in BAL-002-3 regarding the development and discussion of plans with the Reliability Coordinator in real time to restore ACE following a contingency during capacity shortages.

One thing that seems to be overlooked is that both the BA and RC have obligations in other standards to take action if a BA’s ACE is negatively impacting frequency or transmission limits.

The exclusion provisions in the current BAL-002-2 deal with situations where the BA has multiple problems (capacity emergency, previous contingencies or multiple contingencies). The priorities of a Balancing Authority following multiple contingencies are to:

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The role of the Reliability Coordinator is not to manage or approve the local actions taken by the Balancing Authority. The proposed changes would put two sets of hands on the wheel and delay action. This is the equivalent of asking the pilot upon the loss of an engine to map out actions and reach out to the air traffic controller to discuss the pilot's proposal.

The role of the RC is to assist the BA as needed and point out external issues the Balancing Authority might not see. Only if a BA is not taking action and there are likely adverse reliability impacts should the RC intervene.

The original Disturbance Control Standard (DCS) prior to 2007 had basically two requirements:

{C}· Recover from large events less than or equal to MSSC in 15 minutes.

{C}· Replenish your reserves in 90 minutes such that you can recover from subsequent events.

There was an expectation that the BA made best efforts to recover from larger events as demonstrated by the reporting form that included events > MSSC and which NERC has tracked over the years. The remainder of the original DCS just explained how the two requirements above were accomplished in the context of a Reserve Sharing Group as well as provided administrative information to support the standard.

While BAL-002-0 made the original DCS more complex, any operator could understand the objectives and explain how performance is demonstrated. The currently enforceable BAL-002-2 is so complex that we believe no two operators asked to explain compliance would come up with the same answer. Version 3 not only layers complexity in the compliance evaluation; it will distract operators from their primary tasks.

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Likes 0	
Dislikes 0	
Response	
Thank you for your comment. ACE recovery plans are just one provision associated with an exemption. Since FERC directed us to include this provision in the standard, the BA must meet all provisions to obtain exemption to Requirement R1. It's up to the BA to provide the ACE recovery plan to qualify for the exemption. All other standards are still applicable such as BAL-001, IROLs, etc. and it is up to the BA to address these other standards with the RC.	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	Yes
Document Name	
Comment	
PPL NERC Registered Affiliates suggests that NERC post a complete redline of Proposed Reliability Standard BAL-002-3 to ensure the industry is fully aware of the transition of the Supplemental Material to a Technical Rationale document. The Redline to Last Approved Version of Proposed Reliability Standard BAL-002-3 posted to the NERC project page on March 22, 2018 is not a complete redline as it does not show the removal of the "Supplemental Material" (also known as Technical Rationale), which is currently included in the effective version BAL-002-2(i).	

Furthermore, the document entitled "Rationales for BAL-002-3" should be entitled "Technical Rationale for BAL-002-3" in accordance with the NERC Technical Rationale for Reliability Standards Policy, and a redline to the last version of this document approved by industry should also be posted.

Additionally, the document entitled "Rationales for BAL-002-3" seems to include implementation guidance as it states "Requirement R1 does not apply when…".

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT will pass your comment on the the appropriate NERC staff.	
Cynthia Kneisl - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	

We have concerns related to the unintended reliability consequences associated with the proposed changes in BAL-002-3 regarding the development and discussion of plans with the Reliability Coordinator in real time to restore ACE following a contingency during capacity shortages.

One thing that seems to be overlooked is that both the BA and RC have obligations in other standards to take action if a BA's ACE is negatively impacting frequency or transmission limits.

The exclusion provisions in the current BAL-002-2 deal with situations where the BA has multiple problems (capacity emergency, previous contingencies or multiple contingencies). The priorities of a Balancing Authority following multiple contingencies are to:

- Assess the incoming alarms and determine the extent of the problem.
- Prioritize actions depending on the location of the event, whether there is a frequency issue or what transmission is being negatively impacted.

- Direct generators to load to correct ACE or to adjust (in coordination with the Transmission Operator) to manage flows.
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The role of the RC is to assist the BA as needed and point out external issues the Balancing Authority might not see. Only if a BA is not taking action and there are likely adverse reliability impacts should the RC intervene.

The original Disturbance Control Standard (DCS) prior to 2007 had basically two requirements:

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While BAL-002-0 made the original DCS more complex, any operator could understand the objectives and explain how performance is demonstrated. The currently enforceable BAL-002-2 is so complex that we believe no two operators asked to explain compliance would come up with the same answer. Version 3 not only layers complexity in the compliance evaluation; it will distract operators from their primary tasks.

We are layering complexity in this standard at the same time NERC has a major project to streamline and focus the standards. Reliability would be better served if the standard were simplified under the Standards Efficiency Review process to the following requirements:

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- Make best efforts and report recovery performance for events > MSSC or when reserves are diminished due to other contingencies.

As mentioned earlier, BAs are still held to the Balancing Authority ACE Limit as well as IROL requirements no matter what the size of the event. NERC collects DCS performance data for its State of Reliability Report, to include events > MSSC. NERC's report shows that BA performance has been stellar. If problems develop in the future, new requirements can be implemented.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. ACE recovery plans are just one provision associated with an exemption. Since FERC directed us to include this provision in the standard, the BA must meet all provisions to obtain exemption to Requirement R1. It's up to the BA to provide the ACE recovery plan to qualify for the exemption.

All other standards are still applicable such as BAL-001, IROLs, etc. and it is up to the BA to address these other standards with the RC.

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	Yes
Document Name	

Comment

Since it is necessary for a Balancing Authority to be in the conditions described in the first three bullets and have communicated those conditions to their Reliability Coordinator in order to be declared in an EEA, it is not necessary to repeat those steps in the proposed language in the fourth bullet of 1.3.1. The resulting fourth bullet would then read "has provided the Reliability Coordinator with an ACE recovery plan, including target recovery time

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. FERC directed the SDT to include this provision as one of the conditions for exemption. The SDT took extreme care to assure we referenced the provisions within the Energy Emergency Alert procedures.	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

It appears that this version needs some clean-up prior to the final version. Texas RE noticed the following:

- The grammatical structure of Requirement 1 Part 1.3 is unclear as to whether the bullets are just for the RSG or the BA as well.
- In the "Rationales" document there is a reference to changes in definition of Contingency Reserve "in the posting" but it does not specify which posting.
- Texas RE requests to see a draft updated CR Form 1 since it is an associated document in Section F of the standard. Will this form be housed with the related documents?

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes that the current language provides sufficient clarity.	

End of Report

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard is adopted by the Board of Trustees.

Description of Current Draft

Completed Actions	Date
SAR posted for comment	06/20/17 – 07/20/17

Anticipated Actions	Date
45-day formal comment period with initial ballot	February 2018 through March 2018
10-day final ballot	April 2018
NERC Board (Board) adoption	May 2018

A. Introduction

1. **Title:** Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

2. **Number:** BAL-002-3

3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.

4. **Applicability:**

   4.1. Responsible Entity

   4.1.1. Balancing Authority

   4.1.1.1. A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Reserve Sharing Group.

   4.1.2. Reserve Sharing Group

5. **Effective Date:** See the Implementation Plan for BAL-002-3.

B. Requirements and Measures

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity:

1.3.1 is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that:

- is experiencing a Reliability Coordinator declared Energy Emergency Alert Level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1. If Requirement R1 part 1.3 applies, then dated documentation that demonstrates compliance with Requirement R1 part 1.3 must also be provided.

R2. Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M2. Each Responsible Entity will have the following documentation to show compliance with Requirement R2:

- a dated Operating Process;
- evidence to indicate that the Operating Process has been reviewed and maintained annually; and,
- evidence such as Operating Plans or other operator documentation that demonstrate that the entity determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency are included in this process.

R3. Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration Period resets the beginning of the Contingency Event Recovery Period. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Responsible Entity will have documentation demonstrating its Contingency Reserve was restored within the Contingency Reserve Restoration Period, such as historical data, computer logs or operator logs.

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 Responsible Entity shall retain data or evidence to show compliance for the current year, plus three previous 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 Responsible Entity is found noncompliant, it shall keep information related to the noncompliance 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 Assessment Processes:

As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" 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.

1.4. Additional Compliance Information

The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	The Responsible Entity achieved less than 100% but at least 90% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period OR The Responsible Entity failed to use CR Form 1 to document a Reportable Balancing Contingency Event.	The Responsible Entity achieved less than 90% but at least 80% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 80% but at least 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.
R2.	The Responsible Entity developed and implemented an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to maintain	N/A	The Responsible Entity developed an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to implement the Operating Process.	The Responsible Entity failed to develop an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency.

	annually the Operating Process.			
R3.	The Responsible Entity restored less than 100% but at least 90% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 90% but at least 80% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 80% but at least 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

CR Form 1

BAL-002-3 Rationales

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	February 14, 2006	Revised graph on page 3, "10 min." to "Recovery time." Removed fourth bullet.	Errata
1	September 9, 2010	Filed petition for revisions to BAL-002 Version 1 with the Commission	Revision
1	January 10, 2011	FERC letter ordered in Docket No. RD10-15-00 approving BAL-002-1	
1	April 1, 2012	Effective Date of BAL-002-1	
1a	November 7, 2012	Interpretation adopted by the NERC Board of Trustees	
1a	February 12, 2013	Interpretation submitted to FERC	
2	November 5, 2015	Adopted by NERC Board of Trustees	Complete revision
2	January 19, 2017	FERC Order approved BAL-002-2. Docket No. RM16-7-000	
2	October 2, 2017	FERC letter Order issued approving raising the VRF for Requirement R1 and R2 from Medium to High. Docket No. RD17-6-000.	

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Description of Current Draft

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NERC Board (Board) adoption	May 2018

A. Introduction

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2. **Number:** BAL-002-3~~2~~
3. **Purpose:** To ensure the Balancing Authority or Reserve Sharing Group balances resources and demand and returns the Balancing Authority's or Reserve Sharing Group's Area Control Error to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event.
4. **Applicability:**

    4.1. Responsible Entity

    4.1.1. Balancing Authority

    4.1.1.1. A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Reserve Sharing Group.

    4.1.2. Reserve Sharing Group

5. **Effective Date:** See the Implementation Plan for BAL-002-3~~2~~.

B. Requirements and Measures

R1. The Responsible Entity experiencing a Reportable Balancing Contingency Event shall: *[Violation Risk Factor: High] [Time Horizon: Real-time Operations]*

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity:

1.3.1 is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that~~the Responsible Entity~~:

- is ~~a Balancing Authority~~ experiencing a Reliability Coordinator declared Energy Emergency Alert Level~~ or is a Reserve Sharing Group whose member, or members, are experiencing a Reliability Coordinator declared Energy Emergency Alert level~~, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

M1. Each Responsible Entity shall have, and provide upon request, as evidence, a CR Form 1 with date and time of occurrence to show compliance with Requirement R1. If Requirement R1 part 1.3 applies, then dated documentation that demonstrates compliance with Requirement R1 part 1.3 must also be provided.

R2. Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M2. Each Responsible Entity will have the following documentation to show compliance with Requirement R2:

- a dated Operating Process;
- evidence to indicate that the Operating Process has been reviewed and maintained annually; and,
- evidence such as Operating Plans or other operator documentation that demonstrate that the entity determines its Most Severe Single Contingency and that Contingency Reserves equal to or greater than its Most Severe Single Contingency are included in this process.

R3. Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration Period resets the beginning of the Contingency Event Recovery Period. *[Violation Risk Factor: Medium] [Time Horizon: Real-time Operations]*

M3. Each Responsible Entity will have documentation demonstrating its Contingency Reserve was restored within the Contingency Reserve Restoration Period, such as historical data, computer logs or operator logs.

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 Responsible Entity shall retain data or evidence to show compliance for the current year, plus three previous 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 Responsible Entity is found noncompliant, it shall keep information related to the noncompliance 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 Assessment Processes:
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" 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.

1.4. Additional Compliance Information
The Responsible Entity may use Contingency Reserve for any Balancing Contingency Event and as required for any other applicable standards.

Table of Compliance Elements

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	The Responsible Entity achieved less than 100% but at least 90% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period OR The Responsible Entity failed to use CR Form 1 to document a Reportable Balancing Contingency Event.	The Responsible Entity achieved less than 90% but at least 80% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 80% but at least 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.	The Responsible Entity achieved less than 70% of required recovery from a Reportable Balancing Contingency Event during the Contingency Event Recovery Period.
R2.	The Responsible Entity developed and implemented an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to maintain	N/A	The Responsible Entity developed an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency but failed to implement the Operating Process.	The Responsible Entity failed to develop an Operating Process to determine its Most Severe Single Contingency and to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency.

	annually the Operating Process.			
R3.	The Responsible Entity restored less than 100% but at least 90% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 90% but at least 80% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 80% but at least 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.	The Responsible Entity restored less than 70% of required Contingency Reserve following a Reportable Balancing Contingency Event during the Contingency Event Restoration Period.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~BAL-002-2 Contingency Reserve for Recovery from a Balancing Contingency Event Background Document~~

CR Form 1

BAL-002-3 Rationales

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	February 14, 2006	Revised graph on page 3, “10 min.” to “Recovery time.” Removed fourth bullet.	Errata
1	September 9, 2010	Filed petition for revisions to BAL-002 Version 1 with the Commission	Revision
1	January 10, 2011	FERC letter ordered in Docket No. RD10-15-00 approving BAL-002-1	
1	April 1, 2012	Effective Date of BAL-002-1	
1a	November 7, 2012	Interpretation adopted by the NERC Board of Trustees	
1a	February 12, 2013	Interpretation submitted to FERC	
2	November 5, 2015	Adopted by NERC Board of Trustees	Complete revision
2	January 19, 2017	FERC Order approved BAL-002-2. Docket No. RM16-7-000	
2	October 2, 2017	FERC letter Order issued approving raising the VRF for Requirement R1 and R2 from Medium to High. Docket No. RD17-6-000.	

Implementation Plan

Project 2017-06 Modifications to BAL-002-2

Requested Approvals

- BAL-002-3 Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

Requested Retirements

- BAL-002-2 Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

Applicable Entities

- Balancing Authority
- Reserve Sharing Group

Effective Date

The effective date for proposed Reliability Standard BAL-002-3 is provided below:

Where approval by an applicable governmental authority is required, Reliability Standard BAL-002-3 shall become effective the first day of the first calendar quarter that is six (6) calendar months after the effective date of the applicable governmental authority's order approving the standards and terms, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, Reliability Standard BAL-002-3 shall become effective on the first day of the first calendar quarter that is six (6) calendar months after the date the standards and terms are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Current NERC Reliability Standards

The existing standard BAL-002-2 shall be retired immediately prior to the effective date of the proposed BAL-002-3 standard.

Standards Announcement

Project 2017-06 Modifications to BAL-002-2

Final Ballot Open through July 16, 2018

Now Available

The final ballot for **BAL-002-3 Disturbance Control Standard—Contingency Reserve for Recovery from a Balancing Contingency Event** is open through **8 p.m. Eastern, Monday, July 16, 2018**.

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 associated with this project can log in and submit their votes by accessing the Standards Balloting & Commenting System (SBS) here. If you experience difficulty navigating the SBS, contact Wendy Muller.

- *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.

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

For more information or assistance, contact Principal Technical Advisor, Darrel Richardson (via email), or at (609) 613-1848.

NERC Balloting Tool (/) Dashboard (/) Users Ballots Comment Forms

Login (/Users/Login) / Register (/Users/Register)

BALLOT RESULTS

Ballot Name: 2017-06 Modifications to BAL-002-2 BAL-002-3 FN 2 ST
Voting Start Date: 7/5/2018 9:17:46 AM
Voting End Date: 7/16/2018 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 195
Total Ballot Pool: 231
Quorum: 84.42
Weighted Segment Value: 71.85

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	54	1	30	0.789	8	0.211	0	10	6
Segment: 2	6	0.4	2	0.2	2	0.2	0	1	1
Segment: 3	50	1	20	0.667	10	0.333	0	10	10
Segment: 4	14	0.9	6	0.6	3	0.3	0	2	3
Segment: 5	54	1	26	0.703	11	0.297	0	9	8
Segment: 6	43	1	21	0.724	8	0.276	0	7	7
Segment: 7	1	0	0	0	0	0	0	0	1
Segment: 8	1	0.1	1	0.1	0	0	0	0	0
Segment: 9	1	0.1	1	0.1	0	0	0	0	0
Segment: 10	7	0.6	5	0.5	1	0.1	0	1	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
Totals:	231	6.1	112	4.383	43	1.717	0	40	36

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Jamie Monette		Affirmative	N/A
1	Ameren - Ameren Services	Eric Scott		Negative	N/A
1	APS - Arizona Public Service Co.	Michelle Amarantos		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Joe Tarantino	Affirmative	N/A
1	BC Hydro and Power Authority	Patricia Robertson	Adrian Andreoiu	Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Bonneville Power Administration	Kammy Rogers-Holliday		Affirmative	N/A
1	Colorado Springs Utilities	Devin Elverdi		Affirmative	N/A
1	Dairyland Power Cooperative	Renee Leidel		None	N/A
1	Duke Energy	Laura Lee		Affirmative	N/A
1	Edison International - Southern California Edison Company	Steven Mavis		Affirmative	N/A
1	Entergy - Entergy Services, Inc.	Oliver Burke		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Exelon	Chris Scanlon		None	N/A
1	Gainesville Regional Utilities	David Owens	Brandon McCormick	Negative	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		Negative	N/A
1	IDACORP - Idaho Power Company	Laura Nelson		Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Stephanie Burns	Negative	N/A
1	JEA	Ted Hobson	Joe McClung	Affirmative	N/A
1	Lakeland Electric	Larry Watt		Negative	N/A
1	Lincoln Electric System	Danny Pudenz		Abstain	N/A
1	Long Island Power Authority	Robert Ganley		Affirmative	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	William Sanders		None	N/A
1	Manitoba Hydro	Mike Smith		Abstain	N/A
1	MEAG Power	David Weekley	Scott Miller	Abstain	N/A
1	Muscatine Power and Water	Andy Kurriger		None	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	New York Power Authority	Salvatore Spagnolo		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Mike ONeil		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Steve Toosevich		Negative	N/A
1	NorthWestern Energy	Belinda Tierney		None	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Portland General Electric Co.	Nathaniel Clague		Affirmative	N/A
1	PPL Electric Utilities Corporation	Brenda Truhe		Negative	N/A
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	Public Utility District No. 1 of Snohomish County	Long Duong		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		Affirmative	N/A
1	SCANA - South Carolina Electric and Gas Co.	Tom Hanzlik		Affirmative	N/A
1	Seattle City Light	Pawel Krupa		Affirmative	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	Howell Scott		Negative	N/A
1	Tri-State G and T Association, Inc.	Tracy Sliman		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Westar Energy	Allen Klassen		Abstain	N/A
1	Western Area Power Administration	sean erickson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Xcel Energy, Inc.	Dean Schiro		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Brandon Gleason		Abstain	N/A
2	Independent Electricity System Operator	Leonard Kula		Negative	N/A
2	ISO New England, Inc.	Michael Puscas	Joshua Eason	Affirmative	N/A
2	Midcontinent ISO, Inc.	Terry BIlke		Negative	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Mark Holman		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras		Negative	N/A
3	APS - Arizona Public Service Co.	Vivian Vo		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	Darnez Gresham	Affirmative	N/A
3	Bonneville Power Administration	Rebecca Berdahl		Affirmative	N/A
3	City of Vero Beach	Ginny Beigel	Brandon McCormick	Negative	N/A
3	Cleco Corporation	Michelle Corley	Louis Guidry	Affirmative	N/A
3	CPS Energy	James Grimshaw		None	N/A
3	DTE Energy - Detroit Edison Company	Karie Barczak		None	N/A
3	Duke Energy	Lee Schuster		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Exelon	John Bee		None	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Florida Municipal Power Agency	Joe McKinney	Brandon McCormick	Negative	N/A
3	Gainesville Regional Utilities	Ken Simmons	Brandon McCormick	Negative	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		Negative	N/A
3	Lincoln Electric System	Jason Fortik		None	N/A
3	Los Angeles Department of Water and Power	Henry (Hank) Williams		None	N/A
3	Manitoba Hydro	Karim Abdel-Hadi		Abstain	N/A
3	MEAG Power	Roger Brand	Scott Miller	Abstain	N/A
3	Muscatine Power and Water	Seth Shoemaker		Negative	N/A
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Aimee Harris		Negative	N/A
3	Ocala Utility Services	Randy Hahn		Negative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Owensboro Municipal Utilities	Thomas Lyons		Affirmative	N/A
3	Platte River Power Authority	Jeff Landis		Abstain	N/A
3	Portland General Electric Co.	Angela Gaines		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	Charles Freibert		Negative	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Abstain	N/A
3	Puget Sound Energy, Inc.	Lynda Kupfer		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Rutherford EMC	Tom Haire		None	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		Affirmative	N/A
3	SCANA - South Carolina Electric and Gas Co.	Scott Parker		None	N/A
3	Seattle City Light	Tuan Tran		None	N/A
3	Seminole Electric Cooperative, Inc.	James Frauen		Abstain	N/A
3	Snohomish County PUD No. 1	Holly Chaney		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		Negative	N/A
3	WEC Energy Group, Inc.	Thomas Breene		Affirmative	N/A
3	Westar Energy	Bryan Taggart		Abstain	N/A
3	Xcel Energy, Inc.	Michael Ibold		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	N/A
4	American Public Power Association	Jack Cashin		Abstain	N/A
4	Austin Energy	Esther Weekes		Affirmative	N/A
4	City of Poplar Bluff	Neal Williams		None	N/A
4	Florida Municipal Power Agency	Carol Chinn	Brandon McCormick	Negative	N/A
4	Georgia System Operations Corporation	Andrea Barclay		Abstain	N/A
4	MGE Energy - Madison Gas and Electric Co.	Joseph DePoorter		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Public Utility District No. 1 of Snohomish County	John Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Yvonne McMackin		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.	Anthony Jankowski		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	N/A
5	APS - Arizona Public Service Co.	Kelsi Rigby		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		Affirmative	N/A
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		Negative	N/A
5	Choctaw Generation Limited Partnership, LLLP	Rob Watson		None	N/A
5	City Water, Light and Power of Springfield, IL	Steve Rose		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Dominion - Dominion Resources, Inc.	Lou Oberski		None	N/A
5	DTE Energy - Detroit Edison Company	Jeffrey DePriest		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Exelon	Ruth Miller		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	Brandon McCormick	Negative	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		Negative	N/A
5	Herb Schrayshuen	Herb Schrayshuen		Affirmative	N/A
5	JEA	John Babik		Affirmative	N/A
5	Kissimmee Utility Authority	Mike Blough	Brandon McCormick	Negative	N/A
5	Lakeland Electric	Jim Howard		Negative	N/A
5	Lincoln Electric System	Kayleigh Wilkerson		Abstain	N/A
5	Los Angeles Department of Water and Power	Donald Sievertson		Affirmative	N/A
5	Manitoba Hydro	Yuguang Xiao		Abstain	N/A
5	Massachusetts Municipal Wholesale Electric Company	David Gordon		Abstain	N/A
5	MEAG Power	Steven Grego	Scott Miller	Abstain	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	N/A
5	NaturEner USA, LLC	Eric Smith		Affirmative	N/A
5	NB Power Corporation	Laura McLeod		Affirmative	N/A
5	Nebraska Public Power District	Don Schmit		Abstain	N/A
5	New York Power Authority	Erick Barrios		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	OGE Energy - Oklahoma Gas and Electric Co.	John Rhea		None	N/A
5	Omaha Public Power District	Mahmood Safi		None	N/A
5	Orlando Utilities Commission	Richard Kinas		Negative	N/A
5	Platte River Power Authority	Tyson Archie		Abstain	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PPL - Louisville Gas and Electric Co.	JULIE HOSTRANDER		Negative	N/A
5	Public Utility District No. 1 of Chelan County	Haley Sousa		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Sam Nietfeld		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		Affirmative	N/A
5	SCANA - South Carolina Electric and Gas Co.	Alyssa Hubbard		Affirmative	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	Tennessee Valley Authority	M Lee Thomas		Negative	N/A
5	Tri-State G and T Association, Inc.	Mark Stein		None	N/A
5	U.S. Bureau of Reclamation	Wendy Center		Affirmative	N/A
5	WEC Energy Group, Inc.	Linda Horn		Affirmative	N/A
5	Westar Energy	Derek Brown		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	N/A
6	APS - Arizona Public Service Co.	Nicholas Kirby		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Berkshire Hathaway - PacifiCorp	Sandra Shaffer		None	N/A
6	Black Hills Corporation	Eric Scherr		None	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
6	Edison International - Southern California Edison Company	Kenya Streeter		None	N/A
6	Exelon	Becky Webb		None	N/A
6	Florida Municipal Power Agency	Richard Montgomery	Brandon McCormick	Negative	N/A
6	Florida Municipal Power Pool	Tom Reedy	Brandon McCormick	Negative	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	Negative	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	Luminant - Luminant Energy	Brenda Hampton		None	N/A
6	Manitoba Hydro	Blair Mukanik		Abstain	N/A
6	Muscatine Power and Water	Ryan Streck		Negative	N/A
6	New York Power Authority	Thomas Savin	Shelly Dineen	Abstain	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		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Northern California Power Agency	Dennis Sismaet		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay		Affirmative	N/A
6	Portland General Electric Co.	Daniel Mason		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Karla Barton		None	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	Salt River Project	Bobby Olsen		Affirmative	N/A
6	Santee Cooper	Michael Brown		Affirmative	N/A
6	SCANA - South Carolina Electric and Gas Co.	John Folsom		None	N/A
6	Seattle City Light	Charles Freeman		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Trudy Novak		Abstain	N/A
6	Snohomish County PUD No. 1	Franklin Lu		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		Negative	N/A
6	WEC Energy Group, Inc.	David Hathaway		Affirmative	N/A
6	Westar Energy	Grant Wilkerson		Abstain	N/A
6	Western Area Power Administration	Charles Faust		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Xcel Energy, Inc.	Carrie Dixon		Affirmative	N/A
7	Luminant Mining Company LLC	Stewart Rake		None	N/A
8	David Kiguel	David Kiguel		Affirmative	N/A
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		Affirmative	N/A
10	Midwest Reliability Organization	Russel Mountjoy		Negative	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	SERC Reliability Corporation	Drew Slabaugh		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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Exhibit E

Rationale for BAL-002-3

Rationales for BAL-002-3

February, 2018

Requirement R1

The Responsible Entity experiencing a Reportable Balancing Contingency Event shall:

1.1. within the Contingency Event Recovery Period, demonstrate recovery by returning its Reporting ACE to at least the recovery value of:

- zero (if its Pre-Reporting Contingency Event ACE Value was positive or equal to zero); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event,

or,

- its Pre-Reporting Contingency Event ACE Value (if its Pre-Reporting Contingency Event ACE Value was negative); however, any Balancing Contingency Event that occurs during the Contingency Event Recovery Period shall reduce the required recovery: (i) beginning at the time of, and (ii) by the magnitude of, such individual Balancing Contingency Event.

1.2. document all Reportable Balancing Contingency Events using CR Form 1.

1.3. deploy Contingency Reserve, within system constraints, to respond to all Reportable Balancing Contingency Events, however, it is not subject to compliance with Requirement R1 part 1.1 if the Responsible Entity:

1.3.1 is (i) a Balancing Authority or (ii) a Reserve Sharing Group with at least one member that:

- is a experiencing a Reliability Coordinator declared Energy Emergency Alert Level, and
- is utilizing its Contingency Reserve to mitigate an operating emergency in accordance with its emergency Operating Plan, and
- has depleted its Contingency Reserve to a level below its Most Severe Single Contingency, and
- has, during communications with its Reliability Coordinator in accordance with the Energy Emergency Alert procedures, (i) notified the Reliability Coordinator of the conditions described in the preceding two bullet points preventing the Responsible Entity from complying with Requirement R1 part 1.1, and (ii) provided the Reliability Coordinator with an ACE recovery plan, including target recovery time.

or,

1.3.2 the Responsible Entity experiences:

- multiple Contingencies where the combined MW loss exceeds its Most Severe Single Contingency and that are defined as a single Balancing Contingency Event, or
- multiple Balancing Contingency Events within the sum of the time periods defined by the Contingency Event Recovery Period and Contingency Reserve Restoration Period whose combined magnitude exceeds the Responsible Entity's Most Severe Single Contingency.

Rationale R1

Requirement R1 reflects the operating principles first established by NERC Policy 1 (Generation Control and Performance). Its objective is to assure the Responsible Entity balances resources and demand and returns its Reporting Area Control Error (ACE) to defined values (subject to applicable limits) following a Reportable Balancing Contingency Event. It requires the Responsible Entity to recover from events that would be less than or equal to the Responsible Entity's MSSC. It establishes the amount of Contingency Reserve and recovery and restoration timeframes the Responsible Entity must demonstrate in a compliance evaluation. It is intended to eliminate the ambiguities and questions associated with the existing standard. In addition, it allows Responsible Entities to have a clear way to demonstrate compliance and support the Interconnection to the full extent of its MSSC.

Requirement R1 does not apply when an entity experiences a Balancing Contingency Event that exceeds its MSSC (which includes multiple Balancing Contingency Events as described in R1 part 1.3.2 below) because a fundamental goal of the SDT is to assure the Responsible Entity has enough flexibility to maintain service to Demand while managing reliability. The SDT's intent is to eliminate any potential overlap or conflict with any other NERC Reliability Standard to eliminate duplicative reporting, and other issues.

Commenters suggested a Quarterly Compliance similar to the current reports sent to NERC. The drafting team attempted to draft measurement language and VSL's for quarterly monitoring of compliance to R1. But the drafting team found that the VSL levels developed were likely to place smaller Balancing Authority's (BA) and Reserve Sharing Groups (RSG) in a severe violation regardless of the size of the failure. Therefore, the drafting team has not adopted a quarterly compliance calculation. Also, the proposed requirement and compliance process meets the directive in Paragraph 354 of Order 693.

The language in R1 part 1.3 does not specifically state under which EEA level the exclusion applies to reduce the need for consequent modifications of the BAL-002 standard. Thus, language in Requirement 1 Part 1.3.1 addresses both current and future EEA process. In addition, the drafting team has added language to R 1.3.1 clarifying that if a BA is experiencing an EEA event under which its contingency reserve has been activated, the RSG in which it resides would also be considered to be exempt from R1 compliance.

In addition, to address FERC Order No. 835, the drafting team has modified Requirement R1 Part 1.3.1 to clarify that the Responsible Entity, is the Balancing Authority (BA) notifying the Reliability Coordinator (RC) of the conditions set forth in Requirement R1, Part 1.3.1 in accordance with the Energy Emergency Alert (EEA) procedures. Under the Energy Emergency Alert procedures, the BA must inform the RC of the conditions and necessary requirements to meet reliability and the RC must approve of the information being provided before issuing an Energy Emergency Alert. Requirement R1 Part 1.3.1 requires the BA to provide additional information to the RC, allowing the RC to have a wide-area view of the state of the Bulk Electric System for possible future decisions concerning the System. It also provides for relief to a BA or RSG when reserves are being utilized under an EEA. These modifications keep the issues associated with Energy Emergencies within the Emergency Preparedness and Operations Standards, while allowing BAL-002-3 to compliment the process and clarify the narrow set of conditions where the BA and/or RSG is not subject to compliance to R1..

Requirement R2

Each Responsible Entity shall develop, review and maintain annually, and implement an Operating Process as part of its Operating Plan to determine its Most Severe Single Contingency and make preparations to have Contingency Reserve equal to, or greater than the Responsible Entity's Most Severe Single Contingency available for maintaining system reliability.

Rationale R2

R2 establishes the need to actively plan in the near term (e.g., day-ahead) for expected Reportable Balancing Contingency Events. This requirement is similar to the current standard which requires an entity to have available a level of contingency reserves equal to or greater than its Most Severe Single Contingency.

Requirement R3

Each Responsible Entity, following a Reportable Balancing Contingency Event, shall restore its Contingency Reserve to at least its Most Severe Single Contingency, before the end of the Contingency Reserve Restoration Period, but any Balancing Contingency Event that occurs before the end of a Contingency Reserve Restoration Period resets the beginning of the Contingency Event Recovery Period.

Rationale R3

This requirement is similar to the existing requirement that an entity that has experienced an event shall restore its Contingency Reserves within 105 minutes of the event. Note that if an entity is experiencing an EEA it may need to depend on potential availability (or make ready for potential curtailment) of its firm loads to restore Contingency Reserve. This is the reason for the changes to the definition of Contingency Reserve in the posting.

Exhibit F

Standard Drafting Team Roster

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standard Drafting Team Roster

Project 2017-06 Modifications to BAL-002-2

	Name	Entity
Chair	Jerry Rust	Northwest Power Pool
Co-Chair	Glenn Stephens	Santee Cooper
Members	Gerry Beckerle	Ameren
	Natika Mago	Electric Reliability Council of Texas
	Mark Prosperi-Porta	BC Hydro
	Lonnie L Lindekugel	Southwest Power Pool
	David Kimmel	PJM Interconnection
	Sean Erickson	WAPA
NERC Staff	Darrel Richardson	North American Electric Reliability Corporation
	Robert Cummings	North American Electric Reliability Corporation
	Brad Gordon	North American Electric Reliability Corporation
	Candice Castaneda	North American Electric Reliability Corporation