UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION	))	**Docket No. RD13-_____**

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF INTERPRETATION TO BAL-002-1 – DISTURBANCE CONTROL PERFORMANCE

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The North American Electric Reliability Corporation ("NERC")[1] hereby requests the Federal Energy Regulatory Commission ("FERC" or the "Commission") approve, in accordance with Section 215(d)(1) of the Federal Power Act ("FPA")[2] and Section 39.5 of the Commission's regulations, 18 C.F.R. § 39.5 (2012), a proposed interpretation to Reliability Standard —BAL-002-1–Disturbance Control Performance, which was approved by the NERC Board of Trustees on November 7, 2012. Upon Commission approval of the interpretation, the standard will be referred to as BAL-002-1a.[3]

BAL-002-1 is applicable to Balancing Authorities, Reserve Sharing Groups[4] and Regional Reliability Organizations and maintains interconnection frequency by setting

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[1] NERC has been certified by the Commission as the electric reliability organization ("ERO") in accordance with Section 215 of the Federal Power Act. The Commission certified NERC as the ERO in its order issued July 20, 2006 in Docket No. RR06-1-000. *North American Electric Reliability Corp.*, 116 FERC ¶ 61,062 (2006) ("ERO Certification Order"). Unless otherwise designated, all capitalized terms shall have the meaning set forth in the Glossary of Terms Used in NERC Reliability Standards, available here: http://www.nerc.com/files/Glossary_of_Terms.pdf.

[2] 16 U.S.C. § 824o (2012).

[3] *See* NERC Standards Numbering Convention at 2 ("If a standard has an approved Interpretation, the standard identification will also have a lower case letter after the version number.") *available at*: http://www.nerc.com/files/NERC_Standards_Numbering_Convention_2009Sept14.pdf.

[4] As defined in the Glossary of Terms Used in NERC Reliability Standards, a Reserve Sharing Group is a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in

the Balancing Authority's (or Reserve Sharing Group's or Regional Reliability Organization's) time limit for balancing real power (MW) demand and supply following the sudden failure of generation.

I. <u>EXECUTIVE SUMMARY</u>

The Resource and Demand Balancing ("BAL") group of Reliability Standards ensure that resources and demand are balanced to maintain interconnection frequency within limits. The purpose of the BAL-002 Disturbance Control Performance Reliability Standard is to ensure the Balancing Authority is able to utilize its Contingency Reserve[5] to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance.

Reliability Standard BAL-002-1 establishes: (1) the generic requirements that each applicable entity should use to determine the amount and type of contingency reserves that will be needed to meet a metric called the Disturbance Control Standard ("DCS"); (2) how to calculate the DCS metric; (3) procedures to be used in calculating DCS for reserve sharing groups; (4) a 15 minute default disturbance recovery period; (5) a 90 minute default Contingency Reserve restoration period; and (6) the requirement that Balancing Authorities have access to Contingency Reserves to respond to loss of generation, but not loss of load.

A Reportable Disturbance is "[a]ny event that causes an ACE[6] change greater than or equal to 80% of a Balancing Authority's or reserve sharing group's most severe

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quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.

5 The term "Contingency Reserve" is defined in the NERC Glossary of Terms Used in Reliability Standards as "The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other NERC and Regional Reliability Organization contingency requirements."

6 The term "Area Control Error" or "ACE" is defined in the NERC Glossary of Terms Used in Reliability Standards as "the instantaneous difference between net actual and scheduled interchange, taking

contingency. The definition of a reportable disturbance is specified by each Regional Reliability Organization. This definition may not be retroactively adjusted in response to observed performance."[7]

The proposed interpretation clarifies that: (1) a Disturbance that exceeds the most severe single Contingency,[8] regardless if it is a simultaneous Contingency or non-simultaneous multiple Contingency, would be a reportable event, but would be excluded from compliance evaluation; (2) a pre-acknowledged Reserve Sharing Group would be treated in the same manner as an individual Balancing Authority; however, in a dynamically allocated Reserve Sharing Group, exclusions are only provided on a Balancing Authority member by member basis; and (3) an excludable Disturbance was an event with a magnitude greater than the magnitude of the most severe single Contingency.

The proposed interpretation clarifies that BAL-002-1 is intended to be read as an integrated whole and relies in part on information in the Compliance section of the Reliability Standard.[9] The proposed interpretation is necessary to prevent Registered Entities from shedding load to avoid possible violations of BAL-002, a result that is inconsistent with reliability principles. As the Commission has acknowledged, the Requirements are the most critical element of a Reliability Standard,[10] however, other

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into account the effects of Frequency Bias including correction for meter error." Available here: http://www.nerc.com/files/Glossary_of_Terms.pdf.

7 *See* Glossary of Terms Used in NERC Reliability Standards, available here: http://www.nerc.com/files/Glossary_of_Terms.pdf.

8 Defined in the NERC Glossary of Terms Used in Reliability Standards as "[t]he unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element." Available here: http://www.nerc.com/files/Glossary_of_Terms.pdf.

9 A Reliability Standard includes several components designed to work collectively to identify what entities must do to meet their reliability-related obligations as an owner, operator or user of the Bulk Power System. The components of a Reliability Standard include mandatory Requirements, elements necessary to demonstrate compliance and monitor and assess compliance with Requirements, and an informational section.

10 *Mandatory Reliability Standards for the Bulk Power System*, Notice of Proposed Rulemaking, 71 FR 64,770 (Nov. 3, 2006), FERC Stats. & Regs., Vol IV, Proposed Regulations, ¶ 32,608 (2006) at P 105

information in a Reliability Standard, including in the Compliance section, can and should be used to clarify ambiguities. The proposed interpretation of BAL-002-1 neither expands on any Requirement nor explains how to comply with any Requirement, and provides guidance on the meaning of Requirements R4 and R5 and their sub-parts. For these reasons, NERC respectfully requests that the Commission approve the proposed interpretation.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[11]

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III. BACKGROUND

The following background section sets forth: (a) the regulatory framework applicable to NERC interpretations; (b) NERC's development procedures for

("The most critical element of a Reliability Standard is the Requirements."); *see also Order No. 693* at P 254 ("Where a Reliability Standard can be improved by providing missing Measures or Levels of Non-Compliance or by clarifying ambiguities with respect to Measures or Levels of Non-Compliance, we approve the Reliability Standard and concurrently direct NERC to modify it accordingly.")(internal citation omitted).

[11] Persons to be included on the Commission's service list are indicated with an asterisk. NERC requests waiver of the Commission's rules and regulations to permit the inclusion of more than two people on the service list.

Interpretations; and (c) the History of Project 2009-19, the request for Interpretation by the Northwest Power Pool Reserve Sharing Group.

a. Regulatory Framework

By enacting the Energy Policy Act of 2005,[12] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Nation's bulk power system, and with the duties of certifying an electric reliability organization ("ERO") that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215 of the FPA states that all users, owners, and operators of the bulk power system in the United States will be subject to Commission-approved Reliability Standards.[13]

Section 39.5(a) of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes to become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes to be made effective. The Commission has the regulatory responsibility to approve standards that protect the reliability of the bulk power system and to ensure that such standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest.

b. NERC Reliability Standards Development Procedure and Interpretations

NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes

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12 16 U.S.C. § 824o (2012).

13 *See* Section 215(b)(1)("All users, owners and operators of the bulk-power system shall comply with reliability standards that take effect under this section.").

Manual.[14] In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfy certain of the criteria for approving Reliability Standards. The development process is open to any person or entity with a legitimate interest in the reliability of the bulk power system.

All persons who are directly or materially affected by the reliability of the North American bulk power system are permitted to request an interpretation of a Reliability Standard, as discussed in NERC's *Reliability Standards Development Procedure*, which is incorporated into the Rules of Procedure as Appendix 3A. Upon request, NERC will assemble a team with the relevant expertise to address the interpretation request and present an interpretation for industry ballot. If approved by the ballot pool and the NERC Board of Trustees, the interpretation is appended to the Reliability Standard and filed for approval with the Commission and applicable governmental authorities in Canada to be made effective when approved. When the affected Reliability Standard is next revised using the *Reliability Standards Development Procedure*, the interpretation will then be incorporated into the Reliability Standard. The Reliability Standard interpretation submitted herein was approved by the NERC Board of Trustees on November 7, 2012.

c. History of Project 2009-19, Interpretation of BAL-002-0 Requirements R4 and R5: Request for Interpretation by Northwest Power Pool Reserve Sharing Group

A complete summary of the development of Project 2009-19 is included herein as **Exhibit C**. On September 2, 2009, Northwest Power Pool Reserve Sharing Group

[14] The NERC Rules of Procedure are available here: http://www.nerc.com/page.php?cid=1%7C8%7C169. The current NERC Standard Processes Manual is available here: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf.

("NWPP") submitted a request for interpretation asking for clarification in three specific areas of BAL-002-0, Disturbance Control Performance. The specific areas NWPP requested clarification of are:

- (1) although a Disturbance that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group;

- (2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when
    - (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group, and
    - (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and

- (3) the meaning of the phrase "excluded from compliance evaluation" as used in Section 1.4 ("Additional Compliance Information") of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

NWPP requested clarification in order "to avoid applications of BAL-002-0 that would render the reserve requirement in R3.1 of BAL-002-0 (which calls for 'enough Contingency Reserve to cover the most severe single Contingency') meaningless."[15]

[15] *See* Request for Interpretation at p. 3.

NWPP stated that:

> If a Balancing Authority were to experience a Contingency below the Reportable Disturbance level, it would be expected to recover ACE within 15 minutes, even though the literal words of R4 of BAL-002-0 do not say this. Conversely, if a Balancing Authority were to experience a Disturbance five times greater than its most severe single Contingency, it would be required to report this Disturbance, but would not be required to recover ACE within 15 minutes following a Disturbance of this magnitude.
>
> Any other interpretation would result in treating BAL-002-0 as if it required Balancing Authorities and Reserve Sharing Groups to recover ACE (to zero or pre-Disturbance levels, as applicable) within the 15-minute Disturbance Recovery Period without regard to Disturbance magnitude. This is inconsistent with (a) the reserve requirement specified in R3.1 of BAL-002-0, (b) the text of Section 1.4 of Part D of BAL-002-0, and (c) the documented history of the development of BAL-002-0 (*see, e.g.*, Performance Standards Document, Version 3 (as accepted by NERC Resources Subcommittee on October 23, 2007), which provides in Section D, *Disturbance Control Standard, DCS*, that "An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.")

IV. JUSTIFICATION FOR APPROVAL OF THE PROPOSED RELIABILITY STANDARD INTERPRETATION

The following is set forth below: (a) the procedural history of Reliability Standard BAL-002; (b) the basis and purpose of Reliability Standard BAL-002 and the proposed Interpretation; and (c) the justification for the proposed Interpretation.

a. Procedural History of BAL-002

BAL-002-0 was submitted for Commission approval in Docket No. RM06-16-000 and was accepted in Order No. 693.[16] BAL-002-0 was revised (and therefore renumbered as BAL-002-1) to address two Commission directives from paragraph 321 of Order No. 693. BAL-002-1 was submitted in Docket No. RD10-15-000 and was accepted by the Commission via letter order on January 10, 2011.[17]

b. Basis and Purpose of Reliability Standard and Interpretation

[16] *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).

[17] 134 FERC ¶ 61,015 (2011).

As noted above, the purpose of BAL-002 is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Generator failures are far more common than significant losses of load, and because Contingency Reserve activation does not typically apply to the loss of load, the application of BAL-002 is limited to the loss of supply and does not apply to the loss of load.

Requirement R4 of BAL-002-1 requires Balancing Authorities or Reserve Sharing Groups to meet the Disturbance Recovery Criterion within the Disturbance Recovery period for 100% of Reportable Disturbances.[18] Requirement R5 of BAL-002-1 requires each Reserve Sharing Group to comply with the DCS.[19] The proposed

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[18] **BAL-002-1, Requirement R4**:
R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

> **R4.1.** A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.
>
> **R4.2.** The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance.

[19] **BAL-002-1, Requirement R5:**
R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:

> **R5.1.** The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.
> or
>
> **R5.2.** The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

interpretation clarifies that although a Disturbance that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), the Disturbance is excluded from compliance evaluation and there is no violation of BAL-002-1. This proposed interpretation is based in part on the language in the BAL-002, Additional Compliance Information section, which provides that "if the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, *the loss shall be reported, but excluded from compliance evaluation*."[20] (emphasis added).

c. Justification for Interpretation

The proposed interpretation clarifies that BAL-002-1 is intended to be read as an integrated whole and that although a Disturbance that exceeds the most severe single

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[20] Part D. of BAL-002-1 is the Compliance section of the standard. Section 1.5 of Part D, Additional Compliance Information is as follows:

1.5. Additional Compliance Information

Reportable Disturbances – Reportable Disturbances are contingencies that are greater than or equal to 80% of the most severe single Contingency. A Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group may optionally reduce the 80% threshold, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal operating characteristics are excluded because DCS only measures the recovery from sudden, unanticipated losses of supply-side resources.

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Multiple Contingencies within the Contingency Reserve Restoration Period – Additional Reportable Disturbances that occur after the end of the Disturbance Recovery Period but before the end of the Contingency Reserve Restoration Period shall be reported and included in the compliance evaluation. However, the Balancing Authority or Reserve Sharing Group can request a waiver from the Resources Subcommittee for the event if the contingency reserves were rendered inadequate by prior contingencies and a good faith effort to replace contingency reserve can be shown.

Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), the Disturbance is excluded from compliance evaluation.

As the Commission has acknowledged, the Requirements are the most critical element of a Reliability Standard.[21] However, other information in the Reliability Standard, including in the Compliance section, can and should be used to clarify ambiguities. For example, Measures are intended to gauge or document compliance and the violation of a Measure will almost always result in the violation of a Requirement. The mere fact that Measures appear in a different section of the Reliability Standard does not diminish the ability of a Measure to add clarity to the implementation of a Requirement.

While a Reliability Standard does not require additional information (other than Requirements) to be enforceable, such information is included for guidance purposes, and a Reliability Standard should be read as an integrated whole and not just as an isolated series of Requirements. However, an interpretation cannot and should not be used to substantively *change* a Reliability Standard, as acknowledged on the NERC form for a request for an interpretation of a Reliability Standard. The Standard Process Manual states that a "valid Interpretation response provides additional clarity about one or more Requirements, but does not expand on any Requirement and does not explain how to comply with any Requirement."[22] The instant interpretation of BAL-002-1 neither expands on any Requirement nor explains how to comply with any Requirement, and provides guidance on the meaning of Requirements R4 and R5 and their sub-parts.

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[21] *Mandatory Reliability Standards for the Bulk Power System*, Notice of Proposed Rulemaking, 71 FR 64,770 (Nov. 3, 2006), FERC Stats. & Regs., Vol IV, Proposed Regulations, ¶ 32,608 (2006) at P 105 ("The most critical element of a Reliability Standard is the Requirements."); *see also Order No. 693* at P 254 ("Where a Reliability Standard can be improved by providing missing Measures or Levels of Non-Compliance or by clarifying ambiguities with respect to Measures or Levels of Non-Compliance, we approve the Reliability Standard and concurrently direct NERC to modify it accordingly.")(internal citation omitted).

[22] Standard Process Manual at p. 27.

As NWPP noted in its Request for Interpretation, lack of clarity on the interpretation of this standard potentially has significant financial and operational impacts on all Balancing Authorities and Reserve Sharing Groups. If the Reliability Standard is interpreted to require that ACE be returned to zero even for a Disturbance that exceeds the most severe single Contingency, a Balancing Authority could be required to take drastic operational actions, even when other measures of system reliability (voltage stability, normal frequency, operation within system operating limits, etc.) indicate otherwise.

Interpretation Request:

> **Question 1: Although a Disturbance[23] that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group?**

In response to NWPP's interpretation request, the interpretation drafting team developed, and the industry stakeholders approved, the following interpretation:

Response:

The IDT agrees that the Disturbance would be excluded from compliance. The BAL-002 ***Additional Compliance Information section*** *clearly states:*

> *Simultaneous Contingencies – Multiple contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, <u>the loss shall be reported, but excluded from compliance evaluation</u>.*

For clarity the IDT would like to explain the Team's basis concerning some of the terminology used.

> ***Most Severe Single Contingency (MSSC) –*** *this can be the loss of the BA's or RSG's single largest operating generator, or it can be a known*

[23] Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

> *common mode failure that causes more than one generator to fail when the contingency occurs; or it can be a firm transaction. Although Requirement R3.1 mandates an annual "review" that does not mean an annual value. Note that Requirement R3.1 determines a "prospective" MSSC. MSSC is a variable that the BA knows and operates to in real time. The largest operating generator is known and monitored by a BA. The largest known common mode failure is predefined for the BA; the largest single firm transaction is approved by the BA. Thus the BA knows its MSSC which can vary from hour to hour and minute to minute.*

To be clear a BA is responsible for the MSSC at all times (the MSSC value at any given time may be more or less than the annually identified prospective MSSC).

An undefined "common mode" failure can occur but it is exempted from R4's requirement to meet the BA's or RSG's disturbance recovery criteria within the Disturbance Recovery Period. An undefined common mode failure (i.e. a disturbance that exceeds the MSSC) must be reported to allow the ERO to help ensure that it is not a continuing condition.

BAL-002 has two categories (1) Compliance and reporting (for Reportable Disturbances that must comply with the disturbance recovery criteria within the Disturbance Recovery Period) and (2) Reporting only (for specified disturbances and system conditions) events that are excluded from meeting Requirement R4.

The ***Compliance and reporting category*** *is designed to be used to accumulate all DCS events that are subject to compliance to BAL-002 Requirement R4 (i.e. recover ACE within 15 minutes). These include all single assets as well as all pre-defined common mode failures. The standard originally created Ri (the average percent recovery for a Reportable Disturbance) as a measure of the quarterly compliance for Reportable Disturbances. Where all events greater than 80% were mandatory to report and those less than 80% were permitted to be reported (thus encouraging reporting smaller events).*

The ***Reporting only category*** *is designed to track multiple contingency events that are not subject to Requirement R4. This category is designed to ensure that common mode (single point of failures) events are not missed. Thus if two or more contingencies repeatedly occur, the expectation was that the ERO would have the information to alert the BA that the two contingencies must be considered as a single event and thus considered as the MSSC.*

The ***Performance Standard Reference document*** *initially included with the DCS standard does states "Where RSGs exist, the Regional Reliability Council is to decide either to report on a BA basis or an RSG basis. If an RSG has dynamic membership then… required …to report on a BA basis.*

Interpretation Request:

> **Question 2: With respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group,**

> **does the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency apply both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance?**

In response to NWPP's interpretation request, the interpretation drafting team developed, and the industry stakeholders approved, the following interpretation:

Response:

Requirement R5 is directed to RSGs, where RSG is defined in the NERC Glossary as:

> *A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.*

The standard provides flexibility to BAs regarding the use or non-use of RSGs (Requirement R1.1). Requirement R2 affords the members flexibility in how they organize themselves.

Requirement R1.1 allows, at the option of a BA, or RSG to take on all or part of the responsibilities that BAL-002 places on a BA. However, Requirement R5 allows a BA to "call for activation" of reserves [aka dynamic allocation of membership] moreover, there is no ad hoc recognition of such an RSG's multiple contingencies since a contingency in one BA may or not be referred to the RSG, and the simultaneous contingency in another BA is unknown.

The Technical Document does allow for a pre-acknowledged RSG to report on a composite basis. It can be interpreted that such a pre-acknowledged RSG entity assumes all of the obligations and rights afforded to a single BA and in that case such an RSG would be afforded the same Exclusions as the Exclusions afforded a BA.

In summary, the interpretation is as follows:

- *The Standard was written to provide pre-acknowledged RSGs the same considerations as a single BA for purposes of exclusions from DCS compliance evaluation. Thus for a pre-acknowledged RSG the exclusion rules would be used* *in the same manner as they would be used for a single BA. This applies to both multiple contingencies occurring within one minute or less of each other being treated as a single Contingency and to Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period.*

> *The standard, while recognizing dynamically allocated RSGs, does NOT provide the members of dynamically allocated RSGs exclusions from DCS compliance evaluation on an RSG basis. For members of dynamically allocated RSGs, the exclusions are provided only on a member BA by member BA basis.*

As demonstrated in **Exhibit B**, the interpretation drafting team addressed the meaning of the terms "pre-acknowledged RSGs" and "dynamically allocated RSGs" used in response to Question 2. The interpretation drafting team explained that the terms "pre-acknowledged" and "dynamic" were used in the common English terms to mean (i) an RSG that is "recognized ahead of time rather than after-the-fact;" and (ii) an RSG that is used on an on-call basis and thus its responding members are "not static." The interpretation drafting team explained that a "pre-acknowledged RSG" knows who is participating and who is not. However, a "dynamically allocated RSG" operates only on an on-call basis and cannot determine who is responsible and who is not until everyone who wants to participate has communicated their desire to participate. The Technical Document referenced in the interpretation is available here:

http://www.nerc.com/docs/oc/rs/Item_4e-PSRD_revised_112607.pdf.

Interpretation Request:

Question 3: Clarify the meaning of the phrase "excluded from compliance evaluation" as used in Section 1.4 ("Additional Compliance Information") of Part D of BAL-002-0 and for purposes of the preceding statements, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), does BAL-002-0 require ACE to be recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

In response to NWPP's interpretation request, the interpretation drafting team developed, and the industry stakeholders approved, the following interpretation:

Response:

*The **Additional Compliance Information section** clearly states:*

> ***Simultaneous contingencies** – Multiple contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the Most Severe Single Contingency, the loss shall be reported, but excluded from compliance evaluation.*

Although Requirement R3 does mandate that a BA or RSG activate sufficient Contingency Reserves to comply with DCS for every Reportable Disturbance, there is no requirement to comply with or even report disturbances that are below the Reportable Disturbance level. The averaging obligation does incent calculation and reporting of such lesser events.

If a Balancing Authority were to experience a Disturbance five times greater than its most severe single Contingency, it would be required to report this Disturbance, but would not be required to recover ACE within 15 minutes following a Disturbance of this magnitude.

An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency. Any other interpretation would result in treating BAL-002-0 as if it required Balancing Authorities and Reserve Sharing Groups to recover ACE (to zero or pre-Disturbance levels, as applicable) within the 15-minute Disturbance Recovery Period without regard to Disturbance magnitude. This is inconsistent with (a) the reserve requirement specified in R3.1 of BAL-002-0, (b) the text of Section 1.4 of Part D of BAL-002-0, and (c) the documented history of the development of BAL-002-0 (see, e.g., Performance Standards Document, Version 3 (as accepted by NERC Resources Subcommittee on October 23, 2007), which provides in Section D, Disturbance Control Standard, DCS, that "An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.")

V. OTHER ISSUES

While the proposed interpretation differs from the settlement reached in *PacifiCorp*,[24] in which NERC and Commission Enforcement agreed that language

[24] *PacifiCorp*, 137 FERC ¶ 61,176 at n. 5 (2011)("Enforcement and NERC concluded that BAL-002-0 Requirement R4 applies any time there is a Reportable Disturbance regardless of the number or type of contingencies and that this requirement is not altered by the Additional Compliance Information in

included in the Additional Compliance Information section of the standard is guidance and did not require either the Commission or NERC to provide an exclusion from a compliance action, the PacifiCorp settlement is limited to its specific facts and as a settlement agreement, does not establish legal precedent. The proposed interpretation is necessary in order to prevent Registered Entities from shedding load to avoid possible violations of BAL-002, a result that is inconsistent with reliability principles.

Section D.1.4 of BAL-002-0. In Order No. 693, in which the Commission approved this standard, among others, the Commission emphasized that compliance was determined by the requirements, not other parts of a Reliability Standard: 'while Measures and Levels of Non-Compliance provide useful guidance to the industry, compliance will in all cases be measured by determining whether a party met or failed to meet the Requirement given the specific facts and circumstance of its use, ownership or operation of the Bulk-Power System.' *Mandatory Reliability Standards for the Bulk-Power System*, Order No. 693, FERC Stats. & Regs. ¶ 31,242, at P 253, *order on reh'g*, Order No. 693-A, 120 FERC ¶ 61,053 (2007).").

VI. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission approve the interpretation as set forth in **Exhibit A**, effective as proposed herein.

Respectfully submitted,

/s/ Stacey Tyrewala

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Dated: February 12, 2013

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the foregoing document upon all parties listed on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C. this 12th day of February, 2013.

/s/ Stacey Tyrewala

Stacey Tyrewala

Attorney for North American Electric Reliability Corporation

Exhibit A

Reliability Standard BAL-002-1a with Proposed Interpretation Appended

A. Introduction

1. **Title:** **Disturbance Control Performance**
2. **Number:** BAL-002-1a
3. **Purpose:** The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.
4. **Applicability:**
   - **4.1.** Balancing Authorities
   - **4.2.** Reserve Sharing Groups (Balancing Authorities may meet the requirements of Standard 002 through participation in a Reserve Sharing Group.)
   - **4.3.** Regional Reliability Organizations
5. **(Proposed) Effective Date:** The first day of the first calendar quarter, one year after applicable regulatory approval; or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter one year after Board of Trustees' adoption.

B. Requirements

R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, controllable load resources, or coordinated adjustments to Interchange Schedules.

R1.1. A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard BAL-002.

R2. Each Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:

R2.1. The minimum reserve requirement for the group.

R2.2. Its allocation among members.

R2.3. The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.

R2.4. The procedure for applying Contingency Reserve in practice.

R2.5. The limitations, if any, upon the amount of interruptible load that may be included.

R2.6. The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.

R3. Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.

R3.1. As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies.

R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.

R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance.

R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:

R5.1. The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

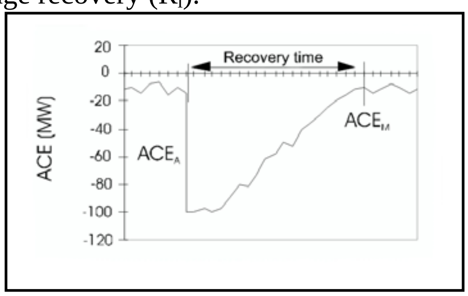
R6. A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection.

R6.1. The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.

R6.2. The default Contingency Reserve Restoration Period is 90 minutes.

C. Measures

M1. A Balancing Authority or Reserve Sharing Group shall calculate and report compliance with the Disturbance Control Standard for all Disturbances greater than or equal to 80% of the magnitude of the Balancing Authority's or of the Reserve Sharing Group's most severe single contingency loss. Regions may, at their discretion, require a lower reporting threshold. Disturbance Control Standard is measured as the percentage recovery (R_i).



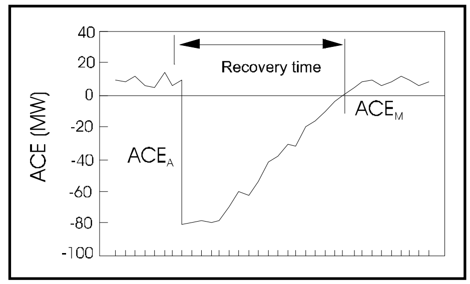
For loss of generation:

if $ACE_A < 0$
then

$$R_i = \frac{MW_{Loss} - \max(0, ACE_A - ACE_M)}{MW_{Loss}} * 100\%$$

if $ACE_A \geq 0$
then

$$R_i = \frac{MW_{Loss} - \max(0, -ACE_M)}{MW_{Loss}} * 100\%$$

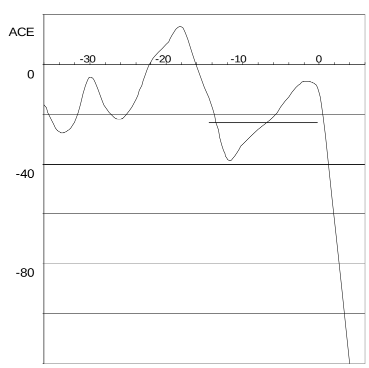


where:

- MW_{LOSS} is the MW size of the Disturbance as measured at the beginning of the loss,
- ACE_A is the pre-disturbance ACE,
- ACE_M is the maximum algebraic value of ACE measured within the fifteen minutes following the Disturbance. A Balancing Authority or Reserve Sharing Group may, at its discretion, set $ACE_M = ACE_{15\ min}$, and

The Balancing Authority or Reserve Sharing Group shall record the MW_{LOSS} value as measured at the site of the loss to the extent possible. The value should not be measured as a change in ACE since governor response and AGC response may introduce error.

The Balancing Authority or Reserve Sharing Group shall base the value for ACE_A on the average ACE over the period just prior to the start of the Disturbance (10 and 60 seconds prior and including at least 4 scans of ACE). In the illustration below, the horizontal line represents an averaging of ACE for 15 seconds prior to the start of the Disturbance with a result of ACE_A = - 25 MW.



The average percent recovery is the arithmetic average of all the calculated R_i's for Reportable Disturbances during a given quarter. Average percent recovery is similarly calculated for excludable Disturbances.

D. Compliance

1. Compliance Monitoring Process

Compliance with the DCS shall be measured on a percentage basis as set forth in the measures above.

Each Balancing Authority or Reserve Sharing Group shall submit one completed copy of DCS Form, “NERC Control Performance Standard Survey – All Interconnections” to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the calendar quarter (i.e. April 10th, July 10th, October 10th, January 10th). The Regional Entity must submit a summary document reporting compliance with DCS to NERC no later than the 20th day of the month following the end of the quarter.

1.1. Compliance Enforcement Authority

Regional Entity.

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance for DCS will be evaluated for each reporting period. Reset is one calendar quarter without a violation.

1.3. Compliance Monitoring and Enforcement Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

The data that support the calculation of DCS are to be retained in electronic form for at least a one-year period. If the DCS data for a Reserve Sharing Group and Balancing Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved.

1.5. Additional Compliance Information

Reportable Disturbances – Reportable Disturbances are contingencies that are greater than or equal to 80% of the most severe single Contingency. A Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group may optionally reduce the 80% threshold, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal operating characteristics are excluded because DCS only measures the recovery from sudden, unanticipated losses of supply-side resources.

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Multiple Contingencies within the Contingency Reserve Restoration Period – Additional Reportable Disturbances that occur after the end of the Disturbance Recovery Period but before the end of the Contingency Reserve Restoration Period shall be reported and included in the compliance evaluation. However, the Balancing Authority or Reserve Sharing Group can request a waiver from the Resources Subcommittee for the event if the contingency reserves were rendered inadequate by prior contingencies and a good faith effort to replace contingency reserve can be shown.

2. Levels of Non-Compliance

Each Balancing Authority or Reserve Sharing Group not meeting the DCS during a given calendar quarter shall increase its Contingency Reserve obligation for the calendar quarter (offset by one month) following the evaluation by the NERC or Compliance Monitor [e.g. for the first calendar quarter of the year, the penalty is applied for May, June, and July.] The increase shall be directly proportional to the non-compliance with the DCS in the preceding quarter. This adjustment is not compounded across quarters, and is an additional percentage of reserve needed beyond the most severe single Contingency. A Reserve Sharing Group may choose an allocation method for increasing its Contingency Reserve for the Reserve Sharing Group provided that this increase is fully allocated.

A representative from each Balancing Authority or Reserve Sharing Group that was non-compliant in the calendar quarter most recently completed shall provide written documentation verifying that the Balancing Authority or Reserve Sharing Group will apply the appropriate DCS performance adjustment beginning the first day of the succeeding month, and will continue to apply it for three months. The written documentation shall accompany the quarterly Disturbance Control Standard Report when a Balancing Authority or Reserve Sharing Group is non-compliant.

3. Violation Severity Levels (no changes)

E. Regional Differences

None identified.

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	August 5, 2010	Adopted by the NERC Board of Trustees	Modified to address Order No. 693 Directives contained in paragraph 321.
1a	November 7, 2012	Interpretation Adopted by the NERC Board of Trustees	

Appendix 1

Request for an Interpretation of a Reliability Standard
Date submitted: September 2, 2009
Date accepted: September 2, 2009
Contact information for person requesting the interpretation:
Name: Northwest Power Pool Reserve Sharing Group, in care of Jerry Rust, Agent
Organization: Northwest Power Pool Reserve Sharing Group
Telephone: 503-445-1074
E-mail: jerry.rust@nwpp.org
Identify the standard that needs clarification:
Standard Number (include version number): BAL-002-0
Standard Title: Disturbance Control Performance
Identify specifically what requirement needs clarification:

Requirement Number and Text of Requirement:

B. Requirements

* * *

R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.

R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.

* * *

R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. * * * Compliance may be demonstrated by either of the following two methods:

R.5.1 The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R.5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

* * *

D. **Compliance**

* * *

1.4 Additional Compliance Information

* * *

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Clarification needed:

The Northwest Power Pool Reserve Sharing Group respectfully requests clarification as to whether:

(1) although a Disturbance[1] that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), the Disturbance is excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group;

(2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and

(3) the meaning of the phrase "excluded from compliance evaluation" as used in Section 1.4 ("Additional Compliance Information") of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve

[1] Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Identify the material impact associated with this interpretation:

Clarification is needed to avoid applications of BAL-002-0 that would render the reserve requirement specified in R3.1 of BAL-002-0 (which calls for "enough Contingency Reserve to cover the most severe single Contingency") meaningless. The intent of BAL-002-0 is that all Contingencies greater than or equal to 80% of the most severe single Contingency constitute "Reportable Disturbances." *See* Section 1.4 of Part D of BAL-002-0 (where the "Additional Compliance Information" includes a definition of "Reportable Disturbance").

If a Balancing Authority were to experience a Contingency below the Reportable Disturbance level, it would be expected to recover ACE within 15 minutes, even though the literal words of R4 of BAL-002-0 do not say this. Conversely, if a Balancing Authority were to experience a Disturbance five times greater than its most severe single Contingency, it would be required to report this Disturbance, but would not be required to recover ACE within 15 minutes following a Disturbance of this magnitude.

Any other interpretation would result in treating BAL-002-0 as if it required Balancing Authorities and Reserve Sharing Groups to recover ACE (to zero or pre-Disturbance levels, as applicable) within the 15-minute Disturbance Recovery Period without regard to Disturbance magnitude. This is inconsistent with (a) the reserve requirement specified in R3.1 of BAL-002-0, (b) the text of Section 1.4 of Part D of BAL-002-0, and (c) the documented history of the development of BAL-002-0 (*see, e.g.,* Performance Standards Document, Version 3 (as accepted by NERC Resources Subcommittee on October 23, 2007), which provides in Section D, *Disturbance Control Standard, DCS*, that "An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.")

Furthermore, lack of clarity on the interpretation of this standard potentially has significant financial and operational impacts on all Balancing Authorities and Reserve Sharing Groups. If the standard is interpreted to require that ACE be returned to zero even for a Disturbance that exceeds the most severe single Contingency, a Balancing Authority could be required to take drastic operational actions, even when other measures of system reliability (voltage stability, normal frequency, operation within system operating limits, etc.) indicate otherwise.

Response:

The Balancing Authority Controls Standard Drafting Team was originally assigned to provide a response to the interpretation request. The original interpretation failed to achieve a two-thirds approval from the industry. NERC appointed a new IDT to develop this interpretation. On July 24, 2012, the team provided the following response to the questions raised:

Question 1: Although a Disturbance[2] that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from

[2] Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group?

Response: The IDT agrees that the Disturbance would be excluded from compliance. The BAL-002 **Additional Compliance Information section** clearly states:

> Simultaneous Contingencies – Multiple contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

For clarity the IDT would like to explain the Team's basis concerning some of the terminology used.

> **Most Severe Single Contingency (MSSC)** – this can be the loss of the BA's or RSG's single largest operating generator, or it can be a known common mode failure that causes more than one generator to fail when the contingency occurs; or it can be a firm transaction. Although Requirement R3.1 mandates an annual "review" that does not mean an annual value. Note that Requirement R3.1 determines a "prospective" MSSC. MSSC is a variable that the BA knows and operates to in real time. The largest operating generator is known and monitored by a BA. The largest known common mode failure is predefined for the BA; the largest single firm transaction is approved by the BA. Thus the BA knows its MSSC which can vary from hour to hour and minute to minute.
>
> To be clear a BA is responsible for the MSSC at all times (the MSSC value at any given time may be more or less than the annually identified prospective MSSC).
>
> An undefined "common mode" failure can occur but it is exempted from R4's requirement to meet the BA's or RSG's disturbance recovery criteria within the Disturbance Recovery Period. An undefined common mode failure (i.e. a disturbance that exceeds the MSSC) must be reported to allow the ERO to help ensure that it is not a continuing condition.

BAL-002 has two categories (1) Compliance and reporting (for Reportable Disturbances that must comply with the disturbance recovery criteria within the Disturbance Recovery Period) and (2) Reporting only (for specified disturbances and system conditions) events that are excluded from meeting Requirement R4 requirement.

The **Compliance and reporting category** is designed to be used to accumulate all DCS events that are subject to compliance to BAL-002 Requirement R4 (i.e. recover ACE within 15 minutes). These include all single assets as well as all pre-defined common mode failures. The standard originally created R_i (the average percent recovery for a Reportable Disturbance) as a measure of the quarterly compliance for Reportable Disturbances. Where all events greater than 80% were mandatory to report and those less than 80% were permitted to be reported (thus encouraging reporting smaller events).

The **Reporting only category** is designed to track multiple contingency events that are not subject to Requirement R4. This category is designed to ensure that common mode (single point of failures) events are not missed. Thus if two or more contingencies repeatedly occur, the expectation was that the ERO would have the information to alert the BA that the two contingencies must be considered as a single

	event and thus considered as the MSSC. The **Performance Standard Reference document** initially included with the DCS standard does states "Where RSGs exist, the Regional Reliability Council is to decide either to report on a BA basis or an RSG basis. If an RSG has dynamic membership then… required …to report on a BA basis.
Question 2:	**With respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, does the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency apply both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance?**
	Response: Requirement R5 is directed to RSGs, where RSG is defined in the NERC Glossary as: A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's <ins>use</ins> in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group. The standard provides flexibility to BAs regarding the use or non-use of RSGs (Requirement R1.1). Requirement R2 affords the members flexibility in how they organize themselves. Requirement R1.1 allows, at the option of a BA, or RSG to take on all or part of the responsibilities that BAL-002 places on a BA. However, Requirement R5 allows a BA to "call for activation" of reserves [aka dynamic allocation of membership] moreover, there is no ad hoc recognition of such an RSG's multiple contingencies since a contingency in one BA may or not be referred to the RSG, and the simultaneous contingency in another BA is unknown. The Technical Document does allow for a pre-acknowledged RSG to report on a composite basis. It can be interpreted that such a pre-acknowledged RSG entity assumes all of the obligations and rights afforded to a single BA and in that case such an RSG would be afforded the same Exclusions as the Exclusions afforded a BA. In summary, the interpretation is as follows: • The Standard was written to provide pre-acknowledged RSGs the same considerations as a single BA for purposes of exclusions from DCS compliance evaluation. Thus for a pre-acknowledged RSG the exclusion rules would be used in the same manner as they would be used for a single BA. This applies to both multiple contingencies occurring within one minute or less of each other being treated as a single Contingency and to Contingencies that occur after one minute of the start of a Reportable

	Disturbance but before the end of the Disturbance Recovery Period. The standard, while recognizing dynamically allocated RSGs, does NOT provide the members of dynamically allocated RSGs exclusions from DCS compliance evaluation on an RSG basis. For members of dynamically allocated RSGs, the exclusions are provided only on a member BA by member BA basis.
Question 3:	**Clarify the meaning of the phrase "excluded from compliance evaluation" as used in Section 1.4 ("Additional Compliance Information") of Part D of BAL-002-0 and for purposes of the preceding statements, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), does BAL-002-0 require ACE to be recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).**

Response: The **Additional Compliance Information section** clearly states:

> **Simultaneous contingencies** – Multiple contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the Most Severe Single Contingency, <u>the loss shall be reported</u>, <u>but excluded from compliance evaluation.</u>

Although Requirement R3 does mandate that a BA or RSG activate sufficient Contingency Reserves to comply with DCS for every Reportable Disturbance, there is no requirement to comply with or even report disturbances that are below the Reportable Disturbance level. The averaging obligation does incent calculation and reporting of such lesser events.

If a Balancing Authority were to experience a Disturbance five times greater than its most severe single Contingency, it would be required to report this Disturbance, but would not be required to recover ACE within 15 minutes following a Disturbance of this magnitude.

An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency. Any other interpretation would result in treating BAL-002-0 as if it required Balancing Authorities and Reserve Sharing Groups to recover ACE (to zero or pre-Disturbance levels, as applicable) within the 15-minute Disturbance Recovery Period without regard to Disturbance magnitude. This is inconsistent with (a) the reserve requirement specified in R3.1 of BAL-002-0, (b) the text of Section 1.4 of Part D of BAL-002-0, and (c) the documented history of the development of BAL-002-0 (*see, e.g.,* Performance Standards Document, Version 3 (as accepted by NERC Resources Subcommittee on October 23, 2007), which provides in Section D, *Disturbance Control Standard, DCS*, that "An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.")

Exhibit B

Consideration of Comments for Proposed Interpretation

Project 2009-19
Interpretation of BAL-002-0 R4 and R5 by NWPP Reserve Sharing Group

Status:

The interpretation was adopted by the NERC Board of Trustees on November 7, 2012, and is pending regulatory approval.

Summary:

The Northwest Power Pool Reserve Sharing Group respectfully requests clarification as to whether:

1. although a Disturbance[1][1] that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), the Disturbance is excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group;
2. with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and
3. the meaning of the phrase "excluded from compliance evaluation" as used in Section 1.4 ("Additional Compliance Information") of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

[1][1] Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

Purpose / Industry Need:

In accordance with the Reliability Standards Development Procedure, the interpretation must be posted for a 30-day pre-ballot review, and then balloted. There is no public comment period for an interpretation. Balloting will be conducted following the same method used for balloting standards. If the interpretation is approved by its ballot pool, then the interpretation will be appended to the standard and will become effective when adopted by the NERC Board of Trustees and approved by the applicable regulatory authorities. The interpretation will remain appended to the standard until the standard is revised through the normal standards development process. When the standard is revised, the clarifications provided by the interpretation will be incorporated into the revised standard.

Appeal:

On January 17, 2012 NERC received a Level 1 Appeal for inaction from the ISO/RTO Council's Standards Review Committee on Project 2009-19 - Northwest Power Pool's Reserve Sharing Group's request for an interpretation of BAL-002-0, Requirement R4. The appellants asked for clarity on the following issues:

- Did NERC, or the Standards Committee, convene the IDT, after comments were received. What industry and/or NERC personnel made up the IDT?
- What accounted for the Standards Committee placing the RFI on hold (in October 2010) and the delay in processing the RFI prior to the Standards Committee 2011 action to place on hold pending Interpretations?'
- Do the Standards Committee Agendas correctly indicate that NERC considered the RFI an invalid request, and if so, why?

IRC Appeal

Data Information Request and Exhibits

NERC Response

Draft	Action	Dates	Results	Consideration of Comments
Draft 2 Northwest Power Pool RSG BAL-002-0 Interpretation Request for Interpretation	Recirculation Ballot Info Vote>>	09/28/12 - 10/08/12	Summary Full Record	
Draft 2 Northwest Power Pool RSG BAL-002-0 Interpretation Request for Interpretation	Successive Ballot Updated Info Info Vote>>	08/23/12 - 09/04/12 (closed)	Summary Full Record	
Supporting Documents: Unofficial Comment Form (Word)	Formal Comment Submit	07/25/12 - 09/04/12 (closed)	Comments Received	Consideration of Comments **(1)**

	Comments>>			
	Join Ballot Pool>>	07/25/12 - 08/23/12 (closed)		
Draft 1 Northwest Power Pool RSG BAL-002-0 Request for Interpretation Interpretation	Initial Ballot Info | Vote>>	02/15/10 - 02/26/10 (closed)	Summary Full Record	
	Pre-ballot Review Info | Join>>	01/15/10 - 02/15/10 (closed)		

Consideration of Comments

Interpretation of BAL-002-0 R4 and R5 by NWPP Reserve Sharing Group
Project 2009-19

The Project 2009-19 Drafting Team thanks all commenters who submitted comments on the proposed Interpretation of BAL-002-0 (R4, R5, and Section D 1.4) for the Northwest Power Pool Reserve Sharing Group. The interpretation was posted for a 45-day public comment period from July 25, 2012 through September 4, 2012. Stakeholders were asked to provide feedback on the interpretation and associated documents through a special electronic comment form. There were 25 sets of comments, including comments from approximately 96 different people from approximately 56 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Of those responders that disagreed with the interpretation, the majority questioned the use of the “Additional Compliance Information” in providing an interpretation of the requirements. The IDT explained that the NERC BOT specifically allowed the use of the reference materials in developing this interpretation. The IDT further explained that the NERC BOT recognized that in the conversion of NERC Policies to Version 0 standards, critical information was placed in sections outside of the requirements themselves and that strict construction policy in the case of the DCS standard was not consistent with the standard itself.

A few of the responders questioned how an RSG was to respond and the amount of time allowed to respond. The IDT explained that the clarification requested by NWPP was not about how an RSG was to respond or the amount of time allowed but instead focused on under what conditions could a Disturbance be excluded for compliance evaluation.

Some responders felt that the terms “pre-acknowledged RSGs” and “dynamically allocated RSGs” were not defined and therefore should not be used. The IDT explained that the terms “pre-acknowledged” and “dynamic” were used in the common English terms to be an RSG that is “recognized ahead of time rather than an after-the-fact”. And an RSG that is used on an on-call basis and thus its responding members are “not static”, respectively.

A few responders questioned why the rules were different for an RSG. The IDT explained that a “pre-acknowledged RSG” knows who is participating and who is not. However, a “dynamically allocated RSG” operates only on an on-call basis and cannot determine who is responsible and who is not until everyone who wants to participate has communicated their desire to participate.

A few responders questioned which version of the BAL-002 (BAL-002-0 or BAL-002-1) this interpretation would apply to. The IDT explained that although the interpretation was requested for BAL-002-0 it would apply to BAL-002-1 as well.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	David Kiguel	Hydro One Networks Inc.	NPCC	1
10.	Michael Lombardi	Northeast Utilities	NPCC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
11.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
12.	Bruce Metruck	New York Power Authority	NPCC	6
13.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
14.	Robert Pellegrini	The United Illuminating Company	NPCC	1
15.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
16.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
17.	Michael Jones	National Grid	NPCC	1
18.	Brian Robinson	Utility Services	NPCC	8
19.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
20.	Donald Weaver	New Brunswick System Operator	NPCC	2
21.	Michael Schiavone	National Grid	NPCC	1
22.	Wayne Sipperly	New York Power Authority	NPCC	5
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Terry Bilke	ISO-RTO Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ben Li	IESO	NPCC	2
2.	Steve Meyers	ERCOT	ERCOT	2
3.	Greg Campoli	NYISO	NPCC	2
4.	Ali Miremadi	CAISO	WECC	2
5.	Charles Yeung	SPP	SPP	2
6.	Kathleen Goodman	NEISO	NPCC	2
7.	Stephanie Monzon	PJM	RFC	2

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Ben Engelby	ACES Power Marketing Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Pablo Onate	El Paso Electric	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dennis Malone	El Paso Electric	WECC	1
2.	Tracy Van Slyke	El Paso Electric	WECC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

3.	David Hawkins	El Paso Electric	WECC	5
4.	Tony Soto	El Paso Electric	WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Greg Rowland	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy	RFC	1
2.	Lee Schuster	Duke Energy	FRCC	3
3.	Dale Goodwine	Duke Energy	SERC	5
4.	Greg Cecil	Duke Energy	SERC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	David Dockery	Associated Electric Cooperative Inc - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	James	Murphy	WECC	1
2.	Fran	Halpin	WECC	5
3.	Erika	Doot	WECC	3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	C. J. Brown	Southwest Power Pool	SPP	2
2.	Ron Gunderson	Nebraska Public Power District	MRO	1, 3, 5
3.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
4.	Heath Martin	Southwest Power Pool	SPP	2
5.	Terry Oxandale	Southwest Power Pool	SPP	2
6.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5
7.	Katie Shea	Westar Energy	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
8.	Jason Smith	Southwest Power Pool	SPP	2									
9.	Carl Stelly	Southwest Power Pool	SPP	2									
10.	Bryan Taggart	Westar Energy	SPP	1, 3, 5, 6									
9.	Group	Gerald Beckerle	SERC Operating Committee Standards Review Team	X	X	X		X	X				X
	Additional Member	Additional Organization	Region	Segment Selection									
1.	Stuart Goza	TVA	SERC	1, 3, 5, 6									
2.	Melinda Montgomery	Entergy	SERC	1, 3, 6									
3.	Oliver Burke	Entergy	SERC	1, 3, 6									
4.	Wayne Van Liere	LGE-KU	SERC	3									
5.	Marie Knox	MISO	SERC	2									
6.	Tim Hattaway	PowerSouth	SERC	1, 5									
7.	Ronnie Douglas	Electric Energy, Inc	SERC	5									
8.	Brad Young	LGE-KU	SERC	3									
9.	Steve Corbin	SERC	SERC	NA									
10.	Pat Huntley	SERC	SERC	NA									
11.	Robert Thomasson	Big Rivers Electric Corp	SERC	1, 3, 5									
12.	Ronnie Douglas	Electric Energy	SERC	1, 3, 5									
10.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
11.	Individual	Michael Falvo	Independent Electricity System Operator		X								
12.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
13.	Individual	Thad Ness	American Electric Power			X		X	X				
14.	Individual	Oliver Burke	Entergy Services, Inc.	X		X		X	X				
15.	Individual	John Appel	Public Utility District #1 of Chelan County	X		X		X	X			X	
16.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
17.	Individual	Carter Edge	SERC										X
18.	Individual	linda Horn	Wisconsin Electric Power Company	X		X		X					
19.	Individual	Greg Travis	Idaho Power Co.										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
20.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	XX				
21.	Individual	Anthony Jablonski	RelliabilityFirst										X
22.	Individual	Maggy Powell	Exelon Corporation	X		X		X	X				
23.	Individual	Brent Ingebrigtson	LG&E and KU Services Company			X							
24.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
25.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Organization	Supporting Comments of "Entity Name"
Public Utility District #1 of Chelan County	Chelan PUD supports the interpretation of BAL-002-0 on behalf of the NWPP.
Electric Reliability Council of Texas, Inc.	ISO SRC
Wisconsin Electric Power Company	We are supporting the comments of MISO.

1. **Do you agree with Response 1 of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language.**

Summary Consideration: The majority of the responders agreed with the interpretation.

Of those responders that disagreed with the interpretation, the majority questioned the use of the "Additional Compliance Information" in providing an interpretation of the requirements. The IDT explained that the NERC BOT specifically allowed the use of the reference materials in developing this interpretation. The IDT further explained that the NERC BOT recognized that in the conversion of NERC Policies to Version 0 standards, critical information was placed in sections outside of the requirements themselves and that strict construction policy in the case of the DCS standard was not consistent with the standard itself.

A few of the responders questioned how an RSG was to respond and the amount of time allowed to respond. The IDT explained that the clarification requested by NWPP was not about how an RSG was to respond or the amount of time allowed but instead focused on under what conditions could a Disturbance be excluded for compliance evaluation.

A few responders referenced ALR 2-5 and stated that this should be carried forward in the future. The IDT explained that this interpretation request was not a question about ALR 2-5. What NWPP asked was if there were two contingencies at the same time, does the standard relieve them of the responsibility to respond in the given time frame. To paraphrase the IDT response, "if a BA experiences two simultaneous contingencies where total output was greater than the BAs MSSC, the BA must respond but will not be responsible to comply with the strictures of the requirement."

Organization	Yes or No	Question 1 Comment
Associated Electric Cooperative Inc - JRO00088	No	Remove: The final paragraph beginning with "The Performance Standard Reference document initially included..."Rationale: A text-search of BAL-002-0, downloaded from the NERC website, fails to yield any instances of the word "dynamic", meaning that it appears nowhere within the four-corners of the BAL-002-0 Standard. Responsible Entities are subject only to the Standard's requirements as written and within its Effective Dates 4/1/2005 to 8/5/2010, when BAL-002-1 effectively replaced it. NERC's BOT Approved August 2, 2006 filing with The Commission appears to contain the

Organization	Yes or No	Question 1 Comment
		oldest copy of FERC approved NERC Glossary of Terms Used in Reliability Standards. It contains no instances of the word “dynamic” that correspond in any way to Reserve Sharing Group membership, although “Reserve Sharing Group” and “Reportable Disturbance” are defined within that document. Although the SDT asserts the augmented concept of RSG dynamic membership, those references within this interpretation should be stricken because the “dynamic membership” concept clearly does not exist within the “four-corners of the Standard” which was balloted and approved by industry stakeholders. Instead BAL-002-0 wording indicates that each RSG can establish its own guidance, necessary to comply with the Requirements. Requirement R2 provides each Reserve Sharing Group the flexibility concerning its policies governing how it collectively fulfills its responsibility to meet Requirements R3, R4, R5 and R6. However Requirement R5’s parenthetical does appear to provide some governance concerning a BA's reporting within a Reserve Sharing Group when they do not call for reserve activation from its other members, that they are subject to individually reporting their performance in responding to that event. (In either case of reporting per R5 parenthetical, the RSG’s collectively-committed units’ spinning-mass and short-term governor response would have fulfilled the reliability objective of this Standard, unless the Reportable Disturbance’s magnitude was much greater than anticipated by the RSG in its entirety.)

Response: Under normal circumstances Associated Electric Cooperative Inc would be correct that only the stated requirements within the four corners of a standard can be referenced in an interpretation. In this case however, the NERC Board of Trustees specifically allowed the Interpretation Drafting Team to make use of reference materials that were created for the original NERC Policy but that in the conversion from NERC Policy to Version 0 standards those materials were placed in sections outside of the requirements themselves. The BOT recognized that strict constructionism in the case of the DCS standard was not consistent with the standard itself and those who drafted the standard.

Organization	Yes or No	Question 1 Comment
Response 1 deals with the issue of excluding a Disturbance that exceeds the most severe single Contingency of a BA or an RSG. Response 1 does not deal with governance. A group of BAs can form an RSG (please note that despite the fact that RSG is a defined term, it does not mean that all RSGs are the same) and decide how to allocate and measure the service it will provide. However, as the cited reference (Performance Standards Guidelines) states (chapter 6, Reporting) "Where RSGs exist, the Regional Reliability Council is to decide either to report these on a BA basis or on an RSG basis." Thus it is clearly not up to the RSG to make that decision about reporting. If the reporting were left to the RSGs then the standard would be a fill-in-the-blanks standard. The RSG would be allowed after-the-fact to decide whether or not two independent losses would be counted as a reason for not reporting. Such an approach would place the system at risk – and the original drafters of that BAL-002 recognized the need to make clear that to take advantage of this benefit, the dynamic RSG (not all RSGs just those that BAs make use of on an as needed basis) must have permission from their Region to address such events on a composite basis. The question raised by NWPP was not about allowing RSGs to respond, the question was about which conditions would exclude a disturbance that exceeded the MSSC of the BA or RSG. It is clear that for a BA any set of non-common mode contingencies that exceed its MSSC would be excluded. For an RSG that has a variable participation, that situation is by definition unclear. Since BA(1) may lose a resource equal to its MSSC and not call for reserve sharing and fail to comply with the standard, however, unknown to BA(1) is the fact that BA(2) also lost a resource at the same time. BA (2) also did not call for reserve sharing and failed to comply. However, after the fact the RSG observes the situation that as a group they would be permitted to exclude the "composite disturbance". The original drafters recognized that fact and precluded that situation by requiring that the Regions decide which MSSC to accept for a BA and which RSGs are permitted to treat themselves as a single BA. The standard was written to serve reliability and not as a means to avoid responding to disturbances. The BOT recognized that fact and allowed the IDT to respond to the NWPP question on the basis of what the drafters meant as indicated by all available reference material and not be limited by the 4 wall of the requirements.		
American Electric Power	No	We do not understand the interpretation provided by the drafting team based on the requirements of BAL-002-0. As a result, we cannot endorse the interpretation provided.

Organization	Yes or No	Question 1 Comment
Response: The interpretation was not based entirely on the requirements of BAL-002-0, but also on the **Additional Compliance Information** section and other reference material (See response to AECI's question 1 comment) as allowed by the BOT.		
SERC	No	The interpretations process is not an appropriate mechanism to address a compliance monitoring and enforcement issue. Further, the words in the requirements do not support the interpretation, no matter how much the interpretation reflects how the industry and ERO have historically approached the Disturbance Control Standard. The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Specifically, Requirement 1 requires each Balancing Authority to have access to and/or operate Contingency Reserve to respond to Disturbances. Prior to penalties and sanctions under Section 215, the consequence of failing DCS was to require an increase in contingency reserves. This is the "compliance evaluation" referred to under Section D. The expectation is that Balancing Areas respond to the loss of resources regardless of magnitude to restore ACE and minimize the risk to reliable operation of being "out of balance". There was recognition, however, that interconnected operations increased the reliability of the grid by reducing the consequences of a single area being out of balance at any given time and thus allowed the collective greater utilization of installed capacity to serve load rather than retain it as contingency reserves. Thus, the concept of "most severe single contingency" (MSSC) as a criterion against which to require additional contingency reserve was employed and for large contingencies may require more time to respond. Fifteen minutes is a "benchmark" time-frame that is reasonable to expect a Balancing Area to recover from a credible contingency. There is nothing magical about that time (it used to be 10 minutes), but the BA should not "lean" on the system longer than is

Organization	Yes or No	Question 1 Comment
		necessary regardless of the magnitude. Performance outside this benchmark can only be determined by an inspection of the facts and circumstances of each instance. All Balancing Authorities and Reserve Sharing Groups are required to review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies. The NERC glossary defines Contingency as the “unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element”. Thus, the compliance action or inaction ("decline to pursue") with respect to the performance of an entity against the stated requirements in the standard is a matter of the CMEP and should not be addressed through the standards interpretations process. Compliance activity should be based on the facts and circumstances of each case measured against the performance requirements of the standard. Standards (including interpretations) are for describing the behaviors and actions of registered entities necessary for the reliable planning and operation of the bulk power system not the Compliance Enforcement Authority. Informed and expert discretion rather than this interpretation (which requires inaction) is a better answer for the Reliability Assurer. Further, ALR 2-5 has a stated purpose as a measure of how much risk a system is exposed to for extreme or unusual contingencies (Simultaneous Contingencies - Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation). The results of ALR 2-5 are expected to help validate current contingency reserve requirements and document how often these “extreme or unusual” contingencies occur. These activities should

Organization	Yes or No	Question 1 Comment
		continue.

Response: The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance.

Prior to penalties and sanctions under Section 215, the consequence of failing DCS was to require an increase in contingency reserves. This is the "compliance evaluation" referred to under Section D.

Thus, the concept of "most severe single contingency" (MSSC) as a criterion against which to require additional contingency reserve was employed and for large contingencies may require more time to respond.

This is not correct. MSSC was used to recognize the fact that the Reserve obligation was to include not simply the largest "generator" but that the largest common mode failure must also be covered. That included single interchange schedules that could be curtailed instantaneously. However, MSSC varies as a function of the assets operating at any given time. Thus the MSSC may be 1500 when a BA's 1500 MW nuclear unit is running, but then becomes 500 when that nuclear unit is off, and the BAs next largest unit is a 500 MW generator.

The time response was not addressed in the NWPP question or in the interpretation. The question NWPP asked was what is excluded from compliance penalty by the DCS standard. It is clear that the standard held BAs to meet the DCS requirement when they had a contingency. It is also clear that contingencies less than 80% of the MSSC were not mandated to be "reported". The drafters of the standard did not intend that contingencies below 80% did not require action, but the consequence of the non-reporting exception provided that situation.

ALR 2.5 is not in question. What NWPP asked was if there are two contingencies at the same time, does the standard relieve them of the responsibility to respond in the given time frame. To paraphrase the IDT response, "if a BA experiences two simultaneous contingencies who total output was greater than the BAs MSSC, the BA must respond but will not be responsible to comply with the strictures of the requirement."

SERC's contention regarding the Reliability Assurer may or may not be true, but the IDT is tasked with interpreting what the standard

Organization	Yes or No	Question 1 Comment
in question says. SERC is welcome to submit a SAR to change the standard.		
ReliabilityFirst	No	ReliabilityFirst votes in the Negative for the Interpretation of BAL-002 since ReliabilityFirst believes the drafted interpretation to Question 1 incorrectly expands on the language in Requirement R4 and incorrectly attempts to explain how to comply with the Requirement. If a reportable disturbance occurs (i.e. contingencies that are greater than or equal to 80% of the most severe single Contingency) and is greater than the most severe single Contingency, ReliabilityFirst questions why an entity would not be required to meet the Disturbance Recovery Criterion. Nowhere within the requirements are there exceptions for Reportable Disturbance greater than the most severe single Contingency. Based on R4, the applicable entity "...shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances". For example, if an entity failed to meet the meet the Disturbance Recovery Criterion for a disturbance equaling 110% of their most severe single Contingency, they would potentially be found non-compliant. In addition, ReliabilityFirst does not believe the quasi definition of "Simultaneous Contingencies" within the "Additional Compliance Information" is not enforceable since it is not a Reliability Requirement, and is not even a NERC Defined term.
Response: Regarding RFC's concern about expanding the language of the requirement, the IDT refers them to the IDT's response to AEC Inc. An IDT is not formed to respond to why a standard mandates what it mandated; the IDT is only obligated to interpret what the drafters meant by the mandated requirement.		

Organization	Yes or No	Question 1 Comment
Regarding Excludable Disturbances RFC is correct that exclusions are not in the requirement, but as explained in the AEC Inc response the IDT was permitted to use other reference material. RFC is referred to the cited reference (Performance Standards Reference Guidelines - http://www.nerc.com/docs/oc/rs/Item_4e-PSRD_revised_112607.pdf) Reporting Section items a.2. And a.3. That specifically references Excludable Disturbances. According to the requirement and the associated reference materials the IDT concludes that a BA cannot be held non-compliant with a disturbance that is 110% of their MSSC. The standard specially excludes such disturbances from compliance. Regarding Simultaneous Contingencies, the IDT would simply refer to the BOT allowance for the IDT to include such reference material.		
LG&E and KU Services Company	No	The IDT's explanation of MSSC may be uneccessary and confusing, especially statements such as: "MSSC is a variable that the BA knows and operates to in real time."" Thus the BA knows its MSSC which can vary from hour to hour and minute to minute."" To be clear a BA is responsible for the MSSC at all times (the MSSC value at any given time may be more or less than the annually identified prospective MSSC)." In the absence of an identifiable/specific reason, which is recognized by the BA in advance, the real-time MSSC should not exceed the prospective MSSC. Unless such an abnormal situation exists, all evaluations of DCS compliance must be based on the prospective MSSC value. The IDT needs to be very clear with any language suggesting that the real-time MSSC can exceed the planned/recognized/"prospective" MSSC. If a disturbance exceeds the planned/recognized/"prospective" MSSC value, it is outside the definition of MSSC and should not be subject to compliance evaluation. The requirement for a prospective MSSC is for the MSSC be used for planning purposes, not for real-time operations, even though it is

Organization	Yes or No	Question 1 Comment
		used in such operations. MSSC is not a defined term in the NERC Glossary but work is in progress under NERC Project 2010-14.1 to develop a definition of MSSC. Therefore, it would not be in the best interest of the IDT in providing this interpretation to attempt to describe or define MSSC. LGE and KU Services recommends all language related to the IDT's explanation of MSSC be deleted from Response 1. Also, the language explaining the "Compliance and reporting category" and "Reporting only category" appears to be outside the inquiry of Question 1 and is suggested for deletion.LGE and KU Services suggests Response 1 be reduced to simply the first sentence of the response as it clearly answers Question 1: "The IDT agrees that the Disturbance would be excluded from compliance."
Response: Thank you, the IDT agrees that it is necessary to be "very clear", hence the explanation. To use the proposed straight forward answer would leave others asking what is meant. Since your answer and our answer agree, the IDT will retain the explanation.		
Electric Reliability Council of Texas, Inc.	No	ERCOT agrees with the SRC comments. However, in addition to the SRC comments, ERCOT offers the following: ERCOT does not agree with additional details in the section that attempts to provide clarification. See the two excerpts below: Quote from Additional Compliance Information section: "To be clear a BA is responsible for the MSSC at all times (the MSSC value at any given time may be more or less than the annually identified prospective MSSC). An undefined "common mode" failure can occur but it is exempted from R4's requirement to meet the BA's or RSG's disturbance recovery criteria within the Disturbance Recovery Period. An undefined common mode failure (i.e. a disturbance that exceeds the MSSC) must be reported to allow the ERO to help ensure that it is not a continuing condition."There should be a period after the word "reported" and the phrase "to allow the ERO to help ensure

Organization	Yes or No	Question 1 Comment
		that it is not a continuing condition." should be struck and removed. Quote from Additional Compliance Information section: "The Reporting only category is designed to track multiple contingency events that are not subject to Requirement R4. This category is designed to ensure that common mode (single point of failures) events are not missed. Thus if two or more contingencies repeatedly occur, the expectation was that the ERO would have the information to alert the BA that the two contingencies must be considered as a single event and thus considered as the MSSC."The entire last sentence should be struck and removed. BA's are the functional entities responsible for coordinating with RC's, other BAs, TOPs, and GOPs to determine if a common mode failure requires a different MSSC. The ERO (NERC) is an oversight entity responsible for developing reliability standards and monitoring and enforcing compliance with those standards. It is not a functional entity. As such, it has no role in functional responsibilities, including the establishment of single contingencies and operating to respect such contingencies in accordance to the applicable NERC standards and requirements. Accordingly, it is inappropriate for the interpretation to suggest, either directly or indirectly, that the ERO is in a position to monitor contingencies on the system, common mode or otherwise, to determine if such reoccurrences warrant consideration of multiple contingencies as a single contingency that could serve as an areas MSCC. There is explicit language in the interpretation that places the ERO in this role. Because this exceeds the scope of the ERO's functions and authority the interpretation must be revised to remove the problematic language. The above revisions are intended to address this issue, and ERCOT respectfully suggests the SDT make the suggested deletions.
Response: The IDT is responsible to interpret what the requirement meant. The idea of having a requirement for reporting excludable disturbances just for the sake of reporting does not make sense. The reason for reporting was to ensure that reliability entities do not take advantage of the exclusion. At the time the standard was written the NERC Performance Subcommittee		

Organization	Yes or No	Question 1 Comment
(translated here to be the ERO) was to collect and evaluate those instances.		
ISO-RTO Standards Review Committee	Yes	We agree with the response. However, we do not agree with some of the details in the section that attempts to provide clarification, excerpt below:"Most Severe Single Contingency (MSSC) - this can be the loss of the BA's or RSG's single largest operating generator, or it can be a known common mode failure that causes more than one generator to fail when the contingency occurs; or it can be a firm transaction."We do not agree the term "firm transaction". The loss of or interruption to a transaction, regardless of its firmness, represents a loss of resource which may trigger the need to comply with the DCS requirement. In other words, a temporary deficiency in a BA's resource has no distinction on whether it is caused by the loss/interruption to a firm transaction or a non-firm transaction. Further, the term "firm transaction" is subject to debate as to whether the firmness is in the energy component or in the transmission service component. If the proposed clarification is to be adopted by registered entities as a guideline for compliance (which this interpretation appears to be attempting to provide), then it can have a potential for opening up a reliability gap since a BA or an RSG may not respond to a resource contingency resulting from the loss or an interruption to a non-firm transaction (however the firmness is interpreted to be). We suggest to remove the word "firm" from the clarification section.
Response: Thank you for your affirmative response and clarifying comment.		
ACES Power Marketing Standards Collaborators	Yes	We conceptually agree with the position of the interpretation. However, we believe that the current response expands issues that were not raised in the original question. One example is that the "MSSC value at any given time may be more or less than the annually identified prospective MSSC" is

Organization	Yes or No	Question 1 Comment
		contradictory to the interpretation. How could the MSSC value could ever be higher than the list of candidate MSSCs identified in the annual review. Also, in the "reporting only" category in response 1, the IDT incorrectly characterizes that the ERO would have authority or the information to alert the BA that two (or more) contingencies must be considered as a single event and thus considered as the MSSC. The ERO does not determine the MSSC, the BA or RSG makes that determination. For simplicity and clarity, we recommend that the interpretation state: Disturbances greater than MSSC are excluded from the compliance calculation, based on the additional compliance information section of BAL-002-0. The IDT could strike everything following this statement from the interpretation and would convey the same message in a more clear and concise manner.
Response: Thank you for your affirmative response and clarifying comment. An MSSC can be higher if the BA expanded its boundaries, or if the BA made an interchange schedule larger than expected.		
El Paso Electric	Yes	El Paso Electric (EPE) generally supports the first interpretation proposed by the IDT but is concerned with the language immediately following "To be clear..." because it does not acknowledge the fact that many BAs have placed responsibility in the hands of a RSG. The interpretation states that "...a BA is responsible for the MSSC at all times...". EPE believes that this responsibility should be shared with a RSG, where appropriate. EPE would be more comfortable with an interpretation that read "To be clear a BA or RSG, as applicable, is responsible for the MSSC at all times..."
Response: The issue in question depends on the type of RSG involved. The BA is responsible. However, if a BA makes use of an RSG then based on the rules of the RSG it could be the BA, it could be the RSG or it could be some combination. The IDT believes that its response properly allows for any of the above. Based on the governance of the RSG and the Region it is in.		
Duke Energy	Yes	We suggest that there should be a SAR to define the terms MSSC and

Organization	Yes or No	Question 1 Comment
		“excludable disturbance” add them to the NERC Glossary.
Response: Thank you for your affirmative response and clarifying comment. There –presently is a project under development to address the issue you have brought forward (Project 2010-14.1 BARC – Reserves).		
SPP Standards Review Group	Yes	This interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		
SERC Operating Committee Standards Review Team	Yes	The SERC OC Standards Review Group gladly presents the following comments. The SERC OC Standards Review Group agrees only with the interpretation portion of the response. The Group strongly disagrees there is a need for the additional explanation of the interpretation. The explanation presents more confusion and questions around the Standard. The simple interpretation is very clear and concise.
Response: Thank you for your affirmative response and clarifying comment.		
Independent Electricity System Operator	Yes	We agree with the response. However, we do not agree with some of the details in the section that attempts to provide clarification, excerpt below:”Most Severe Single Contingency (MSSC) - this can be the loss of the BA’s or RSG’s single largest operating generator, or it can be a known common mode failure that causes more than one generator to fail when the contingency occurs; or it can be a firm transaction.”We do not agree the term “firm transaction”. The loss of or interruption to a transaction, regardless of its firmness, represents a loss of resource which may trigger the need to comply with the DCS requirement. In other words, a temporary deficiency in a BA’s resource has no distinction on whether it is caused by the loss/interruption to a firm transaction or a non-firm transaction.

Organization	Yes or No	Question 1 Comment
		Further, the term “firm transaction” is subject to debate as to whether the firmness is in the energy component or in the transmission service component.If the proposed clarification is to be adopted by registered entities as a guideline for compliance (which this interpretation appears to be attempting to provide), then it can have a potential for opening up a reliability gap since a BA or an RSG may not respond to a resource contingency resulting from the loss or an interruption to a non-firm transaction (however the firmness is interpreted to be). We suggest to remove the word “firm” from the clarification section.
Response: Thank you for your affirmative response and clarifying comment. See our response to SRC.		
Nebraska Public Power District	Yes	The interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		
Idaho Power Co.	Yes	
South Carolina Electric and Gas	Yes	
Exelon Corporation	Yes	
Kansas City Power & Light	Yes	
Northeast Power Coordinating Council	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 1 Comment
Manitoba Hydro	Yes	
Entergy Services, Inc.	Yes	

2. Do you agree with Response 2 of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language.

Summary Consideration: The majority of the responders agreed with the interpretation.

Of those responders that disagreed with the interpretation the majority felt that the terms "pre-acknowledged RSGs" and "dynamically allocated RSGs" were not defined and therefore should not be used. The IDT explained that the terms "pre-acknowledged" and "dynamic" were used in the common English terms to be an RSG that is "recognized ahead of time rather than an after-the-fact". And an RSG that is used on an on-call basis and thus its responding members are "not static", respectively.

A few responders questioned why the rules were different. The IDT explained that a "pre-acknowledged RSG" knows who is participating and who is not. However, a "dynamically allocated RSG" operates only on an on-call basis and cannot determine who is responsible and who is not until everyone who wants to participate has communicated their desire to participate.

Organization	Yes or No	Question 2 Comment
Duke Energy	No	It's not clear what the drafting team is saying, particularly the reference to "dynamic allocation of membership". What's the difference between pre-acknowledged RSGs and dynamically allocated RSGs, and why are the exclusion rules different?
Response: RSG as it pertains to structure is not a common entity. Some RSG are designed to be "on-call" and hence have a dynamic membership. The aforementioned RSG could consist of a pool of 20 BAs, but have 2 (of 20) members who are responding for one disturbance and 15 (of 20) for the next. While the pool of BAs may be fixed, based on the governance of the particular RSG, the obligations of the RSG are allocated only to those who agree to participate for the given disturbance. Of course other RSGs may operate as a unit for all disturbances that occur and thus all pool members are obligated for all disturbances (in effect they become a single BA for purposed of DCS).		

Organization	Yes or No	Question 2 Comment
The exclusion is really the same, what is different is in deciding who is to be counted in multiple disturbances (note this difference is small since the probability of one BA in an RSG having a disturbance at the same as another BA having an independent disturbance is low). But the fact remains that weather conditions could and do span multiple BAs and can result in such simultaneous disturbances (although it is more likely that one BA would be more likely to experience such independent disturbances.) For a pre-acknowledge RSG, one knows exactly who is participating and who is not. In an RSG that operates only on an on-call basis (i.e. a dynamically-allocated RSG) one cannot determine who is responsible and who is not UNTIL everyone who wants to participate has communicated their participation.)		
SERC Operating Committee Standards Review Team	No	The SERC OC Standards Review Group feels the interpretation and clarification are both very confusing, thus raising numerous other questions. The use of the words “pre-acknowledged RSGS” and “dynamic allocated RSGS” appear to be new terms introduced in the response. Also, a reference to a Technical Document is made in the response. The Group is unsure of what Technical Document the IDT is referring. Nor does the Group understand if such reference to the Technical Document is an agreement with such document by the IDT or if the Technical Document is referenced as to be included in the response and subject to being opened and the processes and procedures of such document being made part of a compliance audit.
Response: The Technical document can be found at the following link. **http://www.nerc.com/docs/oc/rs/Item_4e-PSRD_revised_112607.pdf** The BOT recognized that the creation of DCS was supported by other materials such as Reference Documents and a Frequently Asked Questions. These documents hold the key to what was meant by the DCS requirements and are important in any interpretation.		
American Electric Power	No	We do not understand the interpretation provided by the drafting team based on the requirements of BAL-002-0. As a result, we cannot endorse the interpretation provided. For example, it is not clear to us exactly what “pre-acknowledged” or “dynamic” means in regards to Reserve Sharing Groups. These terms are not found anywhere within the standard itself, nor are they commonly used to describe or qualify Reserve Sharing Groups.

Organization	Yes or No	Question 2 Comment
Response: The terms "pre-acknowledged" and "dynamic" are used in the common English terms to be an RSG that is "recognized ahead of time rather than after-the-fact", and an RSG that is used on an on-call basis and thus its responding members are "not static", respectively.		
SERC	No	See answer to question #1.
Response: See response to Question #1		
LG&E and KU Services Company	No	The meaning and use of the adjectives "pre-acknowledged" and "dynamically allocated" in description of RSG in Response 2 seem to be uneccessary, confusing and beyond the scope of Question 2. As stated in Response 2, there is a NERC Glossary definition of RSG and that is the subject of Question 2 - not the applicability of R5 to organizational variations of RSGs. The IDT has referenced a "Technical Document" that has not been included in the posting. The content therefore of the Technical Document is unknown. LGE and KU Services suggests Response 2 be reduced to only the language used in the "In summary,...." portion of the response as it clearly answers Question 2, edited as follows:"The Standard was written to provide RSGs the same considerations as a single BA for purposes of exclusions from DCS compliance evaluation. Thus for a RSG the exclusion rules would be used in the same manner as they would be used for a single BA. This applies to both multiple contingencies occurring within one minute or less of each other being treated as a single Contingency and to Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period."
Response: Question 2 is about exclusions for RSGs. The reference material (http://www.nerc.com/docs/oc/rs/Item_4e-PSRD_revised_112607.pdf) makes the distinction about whether or not the Region agrees ahead of time (pre-acknowledged) or whether or not there is an known MSSC for the RSG (if the responders are dynamically joining or not). Thank-you for your suggestion, but given the responses to the interpretation, the IDT will retain the explanation.		

Organization	Yes or No	Question 2 Comment
ACES Power Marketing Standards Collaborators	Yes	We largely agree with the interpretation. However, we want to point out that the concept of pre-acknowledged RSGs have disincentivized Adjacent Balancing Authorities (not in a pre-acknowledged RSG) to provide reserves in less than 10 minutes even if they are capable. If an Adjacent Balancing Authority provides emeregency energy in an amount that exceeds its own MSSC with a ramp less than 10 minutes and fails to recover its ACE from within 15 minute of the initial disturbance, the Adjacent BA may be found non-compliant despite the fact the it provided the appropriate reliability assistance. Compliance should not disincentivize actions that ensure reliability.
Response: The IDT agrees that the terms of an agreement may influence a BA on agreeing to participate in a given type of RSG. But the responsibility and allocation of penalties is a governance matter defined with the dictates of the agreement the BA signs, it is not a matter for the requirement. This interpretation neither incents of dis-incents making an agreement of any kind. If an entity does not agree with the rules of a proposed RSG agreement they are not obligated by this interpretation to sign that agreement.		
El Paso Electric	Yes	EPE generally supports the second interpretation by the IDT but requests that IDT clarify the scope of compliance evaluations for BAs who are part of a RSG and experienced a reportable event, without regard to whether any individual BA member of the RSG requested assistance. If a RSG determines that the group as a whole complied with CPS then there should be no need for any individual BA review or reporting under R5, without regard to whether the BA called for reserve activation from other RSG members, or not. The interpretation should include this clarification.
Response: This interpretation is based on the concept that BAs would submit "Reportable Disturbances". These reports provide more than compliance information, they provide information on the state of responses. This information was deemed valuable to the Resources Subcommittee. Even in today's environment there is a need to "self-report" non-compliance. The question raised by the NWPP is for a situation in which a BA is non-compliant with the DCS requirement but because of circumstances (explained in the Reference documents and in the Interpretation), the BA is excused from complying with the requirement (i.e. the disturbance is excludable). The decision for		

Organization	Yes or No	Question 2 Comment
exclusion should be easy but as indicated by some responses there are CEAs who say they would hold entities non-compliant for such events.		
SPP Standards Review Group	Yes	Again, this interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		
Nebraska Public Power District	Yes	The interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		
Electric Reliability Council of Texas, Inc.	Yes	ERCOT agrees with the SRC comments.
Response: Thank you for your affirmative response and clarifying comment.		
Associated Electric Cooperative Inc - JRO00088	Yes	Rationale: In our opinion, the IDT failed to answer Question #2, which could have been answered with a simple "Yes". Instead, they appear to attempt legislating upon particulars of how all RSGs should structure portions of their policies under R2, by again referring to the concept of "dynamic membership". Our understanding is that such expansion of Standard governance can only be done under SDT effort and subsequent industry approval through the ballot process. (See AECI's earlier response to Question 1 above.)
Response: Thank you for your affirmative response and clarifying comment.		
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 2 Comment
Arizona Public Service Company	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
Entergy Services, Inc.	Yes	
Idaho Power Co.	Yes	
South Carolina Electric and Gas	Yes	
RelliabilityFirst	Yes	
Exelon Corporation	Yes	
Kansas City Power & Light	Yes	
Northeast Power Coordinating Council	Yes	
ISO-RTO Standards Review Committee	Yes	

3. **Do you agree with Response 3 of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language.**

Summary Consideration: The majority of the responders agreed with the interpretation.

Of those responders that disagreed with the interpretation the majority questioned which version of the BAL-002 (BAL-002-0 or BAL-002-1) this interpretation would apply to. The IDT explained that although the interpretation was requested for BAL-002-0 it would apply to BAL-002-1 as well.

A few responders objected to the wordiness of the response. The IDT explained that their intent was to encourage an understanding of the interpretation. The first two paragraphs were basically a restatement of the requirement and the last paragraph was the actual interpretation.

Organization	Yes or No	Question 3 Comment
Duke Energy	No	It's not clear what the drafting team is saying. Does "excluded from compliance evaluation" mean that R4 does not apply to Disturbances that exceed the MSSC for a BA or RSG? Does it matter if the RSG is pre-acknowledged or dynamically allocated? The drafting team's response to Question 2 seems to indicate that it does matter. We agree that DCS is not applicable for losses greater than the MSSC, and also that DCS compliance is not required for losses less than 80% of the MSSC (or lower if a lower threshold is adopted for DCS reporting). This interpretation is performed on BAL-002-0, but the current effective standard is BAL-002-1 as of 4-1-2012. If the interpretation is approved, what is its applicability to BAL-002-1? Under BAL-002-0 the default Disturbance Recovery Period could be adjusted to better suit the needs of an Interconnection (R4.2) and the default Contingency Reserve Restoration Period could be adjusted to better suit the reliability targets of the Interconnection (R6.2), both based on analysis approved by the NERC Operating Committee. This has been deleted from both requirements in BAL-002-1.

Organization	Yes or No	Question 3 Comment
Response: The IDT believes the interpretation is clear and that the Interpretation would apply to the current version as well as to the former version.		
American Electric Power	No	We do not understand the interpretation provided by the drafting team based on the requirements of BAL-002-0. As a result, we cannot endorse the interpretation provided.
Response: See response to Question #1.		
SERC	No	See Response to question #1.
Response: See response to Question #1		
Exelon Corporation	No	Response 3 of the interpretation that requests clarification on the phrase "excluded from compliance evaluation" could be clearer. The first portion of the response gives the impression that the IDT is of the opinion that the obligation to comply with the DCS extends to events larger in magnitude than the MSSC. The paragraphs that follow go on to clarify that an event greater than the MSSC would not be required to recover ACE within 15 minutes, making compliance with the DCS not mandated in these instances. The latter (disturbances exceeding the MSSC being excluded from DCS compliance and 15 minute recovery) is consistent with practice and in line with the interpretation indicated by the NWPP. In order to more fully clarify the interpretation, the IDT should make clear that compliance with the DCS is not mandated for disturbances exceeding the MSSC.
Response: The first two paragraphs are meant as a restatement of the requirements. The last paragraph is the interpretation.		
ISO-RTO Standards Review Committee	Yes	It might be clearer if the reponse added the phrase [of the Disturbance Control Standard] after "loss shall be reported, but excluded from compliance evaluation".

Organization	Yes or No	Question 3 Comment
		Following a large event, the BA would still be accountable for other standards (e.g. IRO standards)
Response: Thank you for your affirmative response and clarifying comment.		
ACES Power Marketing Standards Collaborators	Yes	We agree for the most part with this interpretation. However, we do have a few points we would like to address. We recommend striking the entire second paragraph because it is irrelevant. The standard does not say comply with DCS "for every reportable disturbance." The key is whether a BA is required to recover ACE within 15 minutes for contingencies greater than MSSC, and that answer is no. The IDT should keep the interpretation simple. A recommendation for wording the interpretation: A BA is not required to recover ACE within 15 minutes for contingencies greater than MSSC, as stated in section 1.4 ("Additional Compliance Information").We recommend that the IDT reduce the amount detail in the rationale and focus on the three questions in the request. The current draft of the interpretation is wordy, confusing and provides excessive details instead of answering the questions that were asked. Also, the IDT did not state that this interpretation would apply to BAL-002-1, which has been enforceable since 4/1/2012. If NERC is going to continue with the interpretation process for BAL-002, the interpretation should apply to both versions of the standard. Finally, we encourage NERC to consolidate standard projects. There are currently 10 standard projects under development for BAL standards. NERC should consider either a consolidation to a reduced amount of BAL projects or even a single project to cover all BAL issues in order to avoid duplication, overlap, inefficient use of resources and confusion.
Response: Thank you for your affirmative response and clarifying comment. The wordy explanation was meant to encourage an understanding of the interpretation. Given the overwhelming support that approach seems to have been effective.		

Organization	Yes or No	Question 3 Comment
The Interpretation would apply to the current version as well as to the former version. This is an interpretation not a standard development. There is a need to respond to this issue as soon as possible. The BAL project may or may not receive approval and to link that Project with this Interpretation would not be helpful to those waiting for this interpretation.		
Associated Electric Cooperative Inc - JRO00088	Yes	We agree with this summary determination. In addition, the August 2, 2006 NERC BOT approved, and subsequently FERC accepted Glossary definition for Reportable Disturbance clearly specified that the definition “not be retroactively adjusted in response to observed performance”, adding weight to this drafting-team’s response to Question 3. (FERC_Filing_Proposed_Reliability_Standards_Docket_RM06-16-000.pdf)
Response: Thank you for your affirmative response and clarifying comment.		
SPP Standards Review Group	Yes	Again, this interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		
Independent Electricity System Operator	Yes	(1) We generally agree with the proposed interpretation. However, we are not sure if this request fits well into NERC’s criteria for acceptance as a valid request since it appears that the requester asks specifically on the compliance implications and compliance elements. We suggest the interpretation drafting team (IDT) to evaluate whether or not the request is a valid one that seeks clarity on the requirements, rather than on the compliance aspects of the standard/requirements. If the IDT does assess that the questions are addressing a compliance issue, then we suggest the IDT to bring this to the attention of the Standards Committee for a determination of the appropriate means to address the questions.

Organization	Yes or No	Question 3 Comment
		(2) The IESO agrees with NERC's interpretation of BAL-002. However, we believe additional discussion and thought need to be applied to other Standards to ensure that no gaps or overlaps exist in both task execution and Standard application. Different Standards obligate Reliability Entities to fulfill certain tasks as it pertains to balancing: conditions. This includes: o BAL- 002 outlines obligations to balance following Reportable Disturbances; o EOP-002 outlines obligations to balance during Capacity and Energy Emergencies; and o TOP-001 outlines obligations to balance during System Emergencies. All of these Standards have similarities but need interpretation to ensure consistent application. These interpretations are based on an understanding of the NERC Functional Model and upon clear statements in the purpose and requirement sections in the Standards. We believe that the objective of each of the Standards list above must be clarified to reduce confusion and support consistent application.
Response: Thank you for your affirmative response and clarifying comment. The IDT is not making a decision on a given compliance issue, it is simply providing an interpretation of what is meant by excludable disturbances. It is not within the purview of an IDT to address other issues outside the bounds of the proposed question. The IESO is encouraged to participate in Projects that address the above requirements or to submit a SAR to rectify their issues and concerns.		
Nebraska Public Power District	Yes	The interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		

Organization	Yes or No	Question 3 Comment
Electric Reliability Council of Texas, Inc.	Yes	ERCOT agrees with the SRC comments.
Response: Thank you for your affirmative response and clarifying comment.		
SERC Operating Committee Standards Review Team	Yes	NONE
El Paso Electric	Yes	No Comment.
Bonneville Power Administration	Yes	BPA is in support of BAL-002-0 Interpretation and has no comments or concerns at this time.
Idaho Power Co.	Yes	
South Carolina Electric and Gas	Yes	
LG&E and KU Services Company	Yes	
Kansas City Power & Light	Yes	
Northeast Power Coordinating Council	Yes	
Arizona Public Service Company	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 3 Comment
Entergy Services, Inc.	Yes	
ReliabilityFirst		ReliabilityFirst disagrees with the drafted interpretation. Regardless of the references to outside sources (the reserve requirement specified in R3.1 of BAL-002-0, the text of Section 1.4 of Part D of BAL-002-0, and the documented history of the development of BAL-002-0), compliance is to be assessed on a requirement by requirement basis. Requirement R4 requires that an applicable entity "...shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances". Clearly, there is no exception listed within the requirements for Reportable Disturbances greater that the most severe single Contingency.
Response: The IDT disagrees with your perception. In addition, the industry ballot indicates that the Industry does not agree with RFC's perception.		

END OF REPORT

Exhibit C

Summary of the Interpretation Development Proceedings and Record of Development of Proposed Interpretation

Exhibit C

I. SUMMARY OF THE INTERPRETATION DEVELOPMENT PROCEEDINGS

The development record for the interpretation of BAL-002-1 is summarized below. **Exhibit C** contains the complete record of development for the proposed standards.

a. Overview of the Interpretation Drafting Team

When evaluating 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 drafting team. For this project, the interpretation drafting team consisted of four industry experts with over 125 years of collective experience. Drafting Team members included Howard Illian of Energy Mark, Inc., who has published a variety of papers on the subject of Frequency Response, including a 2010 report that was funded by the FERC, Office of Electric Reliability,[2] and included a diversity of experience from both the continental United States and Canada. Each individual is considered to be an expert in his field. A detailed set of biographical information for each of the team members is included along with the interpretation drafting team roster in **Exhibit D**.

b. The First Posting and Initial Ballot

Project 2009-19—Interpretation of BAL-002-0 R4 and R5 by NWPP Reserve Sharing Group was initiated on September 2, 2009 by the Northwest Power Pool Reserve Sharing Group as a request for an interpretation of Requirements R4 and R5 of BAL-002-0. The first draft of the interpretation of BAL-002-0 was posted for a pre-ballot review from January 15, 2010 to

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1 Section 215(d)(2) of the Federal Power Act; 16 U.S.C. § 824o(d)(2) (2011).

2 *See e.g.*, Illian, H. (2010). *Frequency Control Performance Measurement and Requirements*, LBNL-2145E, Ernest Orlando Lawrence Berkeley National Laboratory; available at: http://www.ferc.gov/eventcalendar/Files/20110120114346-Frequency-Control-Performance-Measurement-and-Requirements.pdf; Eto, J. H., Undrill, J., Mackin, P., Daschmans, R., Williams, B., Illian, H., et al. (2010). *Use of Frequency Response Metrics to Assess the Planning and Operating Requirements for Reliable Integration of Variable Renewable Generation.* LBNL-4142E. Ernest Orlando Lawrence Berkeley National Laboratory; available at: http://www.ferc.gov/industries/electric/indus-act/reliability/frequencyresponsemetrics-report.pdf.

February 15, 2010. The draft interpretation was then posted for an initial ballot from February 15, 2010 to February 26, 2010.

The Balancing Authority Controls standard drafting team was originally assigned to provide a response to the interpretation request. This standard drafting team developed a response using only the information within the requirements of the standard and the interpretation received only a 48.60% approval rating. The standard drafting team determined that any further interpretation could not be developed unless the team could consider measures and the additional compliance elements of the standard.

c. Level 1 Appeal

On January 17, 2012, NERC received a Level 1 Appeal for inaction from the Standards Review Committee ("SRC") of the ISO/RTO Council on Project 2009-19 in accordance with the NERC Standard Processes Manual. The appellants asked for clarity on the following issues:

- Did NERC, or the Standards Committee, convene the IDT, after comments were received. What industry and/or NERC personnel made up the IDT?
- What accounted for the Standards Committee placing the RFI on hold (in October 2010) and the delay in processing the RFI prior to the Standards Committee 2011 action to place on hold pending Interpretations?
- Do the Standards Committee Agendas correctly indicate that NERC considered the RFI an invalid request, and if so, why?

As part of the appeal process, NERC's Vice President and Director of Standard and Training issued a data request to the NERC Standards staff involved in the development of the interpretation. On March 28, 2012, NERC's Vice President and Director of Standards and Training formally responded to the appeal in a letter addressed to the Chairman of the ISO/RTO

Council SRC. The NERC staff response to the data request was included with the letter.[3] NERC concluded that the appeal could not be substantiated based on the evidence presented by NERC staff in the data response. NERC found that although there was an initial delay in action during which the policy and practices for handling interpretations were being modified by the NERC Board of Trustees and the Standards Committee, NERC staff did in fact take action. NERC created an interpretation drafting team in response to the RFI, conducted an industry ballot, and ultimately deemed the RFI ineligible for the formation of an interpretation under the newly modified rules for developing interpretations.

However, in May 2012, NERC staff presented the issue of whether interpretations can be developed based on language outside of Requirements to the Board of Trustees Standards Oversight and Technology Committee ("SOTC") for consideration. The SOTC determined at that meeting that interpretations may be developed using any language in the standard, including compliance related sections. The minutes from that meeting reflect the discussion as follows:

> **Need for Relief from Interpretation Policy – BAL-002**
> Mr. Herb Schrayshuen, vice president and director of standards and training provided an overview of the issues regarding the BAL-002 interpretation. After significant discussion the committee rejected the approach of a onetime waiver in favor of addressing the issue on a policy level more comprehensively. The conclusion is that strict construction for the purposes of interpretation was never meant to limit the materials considered in developing the interpretation solely to the contents of the requirements in a standard, but can include any language in the standard, including compliance related sections.

Following this determination by the SOTC, the Standards Committee appointed a new interpretation drafting team.

d. The Second Posting – Formal Comment and Successive Ballot

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[3] The NERC letter and data response can be found at http://www.nerc.com/docs/standards/sar/Reply-IRC-Level_1_Appeal_BAL-002_03-28-2012.pdf (Letter) and http://www.nerc.com/docs/standards/sar/IRC_Level_1_Appeal_of_BAL-002RFI-DataRequestandExhibits.pdf (Data Response).

The second draft of the interpretation was posted for a 45-day formal comment period from July 25, 2012 to September 4, 2012. Twenty-five sets of comment were received from ninety-six different individuals from approximately fifty-six companies representing eight of the ten NERC industry segments. The interpretation drafting team did not make changes to the interpretation in response to comments. A minority of commenters expressed concerns with certain parts of the proposed interpretation. These concerns are summarized below.

- Of the commenters that expressed concerns with the interpretation, a number questioned the use of the "Additional Compliance Information" in providing an interpretation of the requirements. The interpretation drafting team explained that the NERC BOT specifically allowed the use of the reference materials in developing this interpretation. The interpretation drafting team further explained that the NERC BOT recognized that in the conversion of NERC Policies to Version 0 standards, critical information was placed in sections outside of the requirements themselves and that strict construction policy in the case of the DCS standard was not consistent with the standard itself.

- Several responders questioned how a Reserve Sharing Group ("RSG") was to respond and the amount of time allowed to respond. The interpretation drafting team explained that the clarification requested by NWPP was not about how an RSG was to respond or the amount of time allowed but instead focused on under what conditions could a Disturbance be excluded for compliance evaluation

- Several responders noted that the terms "pre-acknowledged RSGs" and "dynamically allocated RSGs" were not defined and therefore should not be used. The interpretation drafting team explained that the terms "pre-acknowledged" and "dynamic" were used in the common English terms to be an RSG that is "recognized ahead of time rather than an after-the-fact." And an RSG that is used on an on-call basis and thus its responding members are "not static," respectively.

- A few responders questioned why the rules were different for an RSG. The interpretation drafting team explained that a "pre-acknowledged RSG" knows who is participating and who is not. However, a "dynamically allocated RSG" operates only on an on-call basis and cannot determine who is responsible and who is not until everyone who wants to participate has communicated their desire to participate.

- A few responders questioned which version of the BAL-002 (BAL-002-0 or BAL-002-1) this interpretation would apply to. The IDT explained that although the interpretation was requested for BAL-002-0 it would apply to BAL-002-1 as well.

A successive ballot was held from August 23, 2012 to September 4, 2012. The proposed interpretation achieved a quorum of 79.21% and an approval of 87.78%.

e. Third Posting – Recirculation Ballot

A recirculation ballot of the interpretation to BAL-002-0 was conducted from September 28, 2012 to October 8, 2012. The interpretation achieved a quorum of 85.11% and an approval of 90.34% and was therefore deemed to be approved by the industry.

f. Board of Trustees Approval of Interpretation

The final draft of the interpretation was presented to the NERC Board of Trustees on November 7, 2012. NERC staff provided a summary of the interpretation, as well as a summary of minority issues and associated drafting team responses. The NERC Board of Trustees approved the interpretation, and NERC staff recommended that the interpretation be filed with applicable regulatory authorities.

Project 2009-19
Interpretation of BAL-002-0 R4 and R5 by NWPP Reserve Sharing Group

Status:

The interpretation was adopted by the NERC Board of Trustees on November 7, 2012, and is pending regulatory approval.

Summary:

The Northwest Power Pool Reserve Sharing Group respectfully requests clarification as to whether:

1. although a Disturbance[1][1] that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), the Disturbance is excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group;
2. with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and
3. the meaning of the phrase "excluded from compliance evaluation" as used in Section 1.4 ("Additional Compliance Information") of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

1[1] Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

Purpose / Industry Need:

In accordance with the Reliability Standards Development Procedure, the interpretation must be posted for a 30-day pre-ballot review, and then balloted. There is no public comment period for an interpretation. Balloting will be conducted following the same method used for balloting standards. If the interpretation is approved by its ballot pool, then the interpretation will be appended to the standard and will become effective when adopted by the NERC Board of Trustees and approved by the applicable regulatory authorities. The interpretation will remain appended to the standard until the standard is revised through the normal standards development process. When the standard is revised, the clarifications provided by the interpretation will be incorporated into the revised standard.

Appeal:

On January 17, 2012 NERC received a Level 1 Appeal for inaction from the ISO/RTO Council's Standards Review Committee on Project 2009-19 - Northwest Power Pool's Reserve Sharing Group's request for an interpretation of BAL-002-0, Requirement R4. The appellants asked for clarity on the following issues:

- Did NERC, or the Standards Committee, convene the IDT, after comments were received. What industry and/or NERC personnel made up the IDT?
- What accounted for the Standards Committee placing the RFI on hold (in October 2010) and the delay in processing the RFI prior to the Standards Committee 2011 action to place on hold pending Interpretations?'
- Do the Standards Committee Agendas correctly indicate that NERC considered the RFI an invalid request, and if so, why?

IRC Appeal

Data Information Request and Exhibits

NERC Response

<table>
<tr><th>Draft</th><th>Action</th><th>Dates</th><th>Results</th><th>Consideration of Comments</th></tr>
<tr><td>Draft 2
Northwest Power Pool RSG
BAL-002-0

Interpretation (16)

Request for Interpretation (17)</td><td>Recirculation Ballot

Info (18)

Vote>></td><td>09/28/12 - 10/08/12</td><td>Summary (19)

Full Record (20)</td><td></td></tr>
<tr><td rowspan="2">Draft 2
Northwest Power Pool RSG
BAL-002-0

Interpretation (7)

Request for Interpretation (8)

Supporting Documents:

Unofficial Comment Form (Word) (9)</td><td>Successive Ballot

Updated Info (10)

Info (11)

Vote>></td><td>08/23/12 - 09/04/12 (closed)</td><td>Summary (12)

Full Record (13)</td><td></td></tr>
<tr><td>Formal Comment</td><td>07/25/12 - 09/04/12</td><td>Comments Received (14)</td><td>Consideration of Comments (15)</td></tr>
</table>

	Submit Comments>>	(closed)		
	Join Ballot Pool>>	07/25/12 - 08/23/12 (closed)		
Draft 1 Northwest Power Pool RSG BAL-002-0 Request for Interpretation **(1)** Interpretation **(2)**	Initial Ballot Info **(3)** | Vote>>	02/15/10 - 02/26/10 (closed)	Summary **(5)** Full Record **(6)**	
	Pre-ballot Review Info **(4)** | Join>>	01/15/10 - 02/15/10 (closed)		

Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard	
Date submitted: September 2, 2009	
Date accepted: September 2, 2009	
Contact information for person requesting the interpretation:	
Name:	Northwest Power Pool Reserve Sharing Group, in care of Jerry Rust, Agent
Organization:	Northwest Power Pool Reserve Sharing Group
Telephone:	503-445-1074
E-mail:	jerry.rust@nwpp.org
Identify the standard that needs clarification:	
Standard Number (include version number): BAL-002-0	
Standard Title: Disturbance Control Performance	
Identify specifically what requirement needs clarification:	

Requirement Number and Text of Requirement:

B. Requirements

***

R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.

R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.

***

R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. *** Compliance may be demonstrated by either

of the following two methods:

R.5.1 The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R.5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

***

D. **Compliance**

***

1.4 Additional Compliance Information

***

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

<u>Clarification needed</u>:

The Northwest Power Pool Reserve Sharing Group respectfully requests clarification as to whether:

(1) although a Disturbance[1] that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), the Disturbance is excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group;

(2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve

[1] Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and

(3) the meaning of the phrase "excluded from compliance evaluation" as used in Section 1.4 ("Additional Compliance Information") of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Identify the material impact associated with this interpretation:

Clarification is needed to avoid applications of BAL-002-0 that would render the reserve requirement specified in R3.1 of BAL-002-0 (which calls for "enough Contingency Reserve to cover the most severe single Contingency") meaningless. The intent of BAL-002-0 is that all Contingencies greater than or equal to 80% of the most severe single Contingency constitute "Reportable Disturbances." *See* Section 1.4 of Part D of BAL-002-0 (where the "Additional Compliance Information" includes a definition of "Reportable Disturbance").

If a Balancing Authority were to experience a Contingency below the Reportable Disturbance level, it would be expected to recover ACE within 15 minutes, even though the literal words of R4 of BAL-002-0 do not say this. Conversely, if a Balancing Authority were to experience a Disturbance five times greater than its most severe single Contingency, it would be required to report this Disturbance, but would not be required to recover ACE within 15 minutes following a Disturbance of this magnitude.

Any other interpretation would result in treating BAL-002-0 as if it required Balancing Authorities and Reserve Sharing Groups to recover ACE (to zero or pre-Disturbance levels, as applicable) within the 15-minute Disturbance Recovery Period without regard to Disturbance magnitude. This is inconsistent with (a) the reserve requirement specified in R3.1 of BAL-002-0, (b) the text of Section 1.4 of Part D of BAL-002-0, and (c) the documented history of the development of BAL-002-0 (*see, e.g.,* Performance Standards Document, Version 3 (as accepted by NERC Resources Subcommittee on October 23, 2007), which provides in Section D, *Disturbance Control Standard, DCS*, that "An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.")

Furthermore, lack of clarity on the interpretation of this standard potentially has significant financial and operational impacts on all Balancing Authorities and Reserve Sharing Groups. If the standard is interpreted to require that ACE be returned to zero even for a Disturbance that exceeds the most severe single Contingency, a Balancing Authority could be required to take drastic operational actions, even when other measures of system reliability (voltage stability, normal frequency, operation within system operating limits, etc.) indicate otherwise.

Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard
Date submitted: September 2, 2009
Date accepted: September 2, 2009
Contact information for person requesting the interpretation:
Name: Northwest Power Pool Reserve Sharing Group, in care of Jerry Rust, Agent
Organization: Northwest Power Pool Reserve Sharing Group
Telephone: 503-445-1074
E-mail: jerry.rust@nwpp.org
Identify the standard that needs clarification:
Standard Number (include version number): BAL-002-0
Standard Title: Disturbance Control Performance
Identify specifically what requirement needs clarification:

Requirement Number and Text of Requirement:

B. Requirements

***

R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.

R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.

***

R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. *** Compliance may be demonstrated by either of the following two methods:

R.5.1 The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R.5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

* * *

D. **Compliance**

* * *

1.4 Additional Compliance Information

* * *

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Clarification needed:

The Northwest Power Pool Reserve Sharing Group respectfully requests clarification as to whether:

(1) although a Disturbance[1] that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), the Disturbance is excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group;

(2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and

[1] Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

(3)	the meaning of the phrase "excluded from compliance evaluation" as used in Section 1.4 ("Additional Compliance Information") of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Identify the material impact associated with this interpretation:

Clarification is needed to avoid applications of BAL-002-0 that would render the reserve requirement specified in R3.1 of BAL-002-0 (which calls for "enough Contingency Reserve to cover the most severe single Contingency") meaningless. The intent of BAL-002-0 is that all Contingencies greater than or equal to 80% of the most severe single Contingency constitute "Reportable Disturbances." *See* Section 1.4 of Part D of BAL-002-0 (where the "Additional Compliance Information" includes a definition of "Reportable Disturbance").

If a Balancing Authority were to experience a Contingency below the Reportable Disturbance level, it would be expected to recover ACE within 15 minutes, even though the literal words of R4 of BAL-002-0 do not say this. Conversely, if a Balancing Authority were to experience a Disturbance five times greater than its most severe single Contingency, it would be required to report this Disturbance, but would not be required to recover ACE within 15 minutes following a Disturbance of this magnitude.

Any other interpretation would result in treating BAL-002-0 as if it required Balancing Authorities and Reserve Sharing Groups to recover ACE (to zero or pre-Disturbance levels, as applicable) within the 15-minute Disturbance Recovery Period without regard to Disturbance magnitude. This is inconsistent with (a) the reserve requirement specified in R3.1 of BAL-002-0, (b) the text of Section 1.4 of Part D of BAL-002-0, and (c) the documented history of the development of BAL-002-0 (*see, e.g.,* Performance Standards Document, Version 3 (as accepted by NERC Resources Subcommittee on October 23, 2007), which provides in Section D, *Disturbance Control Standard, DCS*, that "An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.")

Furthermore, lack of clarity on the interpretation of this standard potentially has significant financial and operational impacts on all Balancing Authorities and Reserve Sharing Groups. If the standard is interpreted to require that ACE be returned to zero even for a Disturbance that exceeds the most severe single Contingency, a Balancing Authority could be required to take drastic operational actions, even when other measures of system reliability (voltage stability, normal frequency, operation within system operating limits, etc.) indicate otherwise.

Project 2009-19: Response to Request for an Interpretation of BAL-002-0 for the Northwest Power Pool Reserve Sharing Group
The following interpretation of standard BAL-002-0 — Disturbance Control Performance, Requirements R4 and R5, was developed by several industry experts selected by NERC based on their knowledge of the subject matter.
Requirement Number and Text of Requirement

R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

> **R4.1** A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.
>
> **R4.2.** The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.

R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:

> **R5.1.** The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.
>
> or
>
> **R5.2.** The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

D. Compliance

1.4 Additional Compliance Information

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The

Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.
Question 1:
Although a Disturbance[2] that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group?
Response 1:
The BAL-002-0 Reliability Standard does not grant an exclusion from compliance evaluation for all Disturbances that exceed the most severe single Contingency. The standard excludes from compliance evaluation specific Disturbances. Simultaneous Contingencies that have a combined magnitude in excess of that of the most severe single Contingency are excluded from compliance evaluation. Subsequent contingencies following an initial Reportable Disturbance that occur more than one minute after the start of the Reportable Disturbance but within the Reportable Disturbance Period can be excluded from compliance evaluation; however, the initial Reportable Disturbance is not excluded from compliance evaluation.
Question 2:
With respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, does the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency apply both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance?
Response 2:
As discussed in the response to Question 1, the exclusion from compliance evaluation does not apply to all Disturbances with combined magnitudes exceeding the most severe single Contingency. As described in Requirement R5, the Reserve Sharing Group in its entirety is "considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members." Therefore, the "exclusion from compliance evaluation" would apply, regardless of the location of the Contingencies associated with the Reportable Disturbance within the Reserve Sharing Group, only if: 1. All Reportable Disturbances being considered as contributing to the Reserve Sharing

[2] Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

Group’s Reportable Disturbance condition each had an associated call by the group member with the Reportable Disturbance for the activation of Contingency Reserves from one or more other group members, and 2. The Reserve Sharing Group’s Reportable Disturbance was either based on Simultaneous Contingencies with a combined magnitude in excess of the most severe single Contingency, or was a subsequent contingency that occurred more than one minute after the start of a Reportable Disturbance but within the Reportable Disturbance Period.
Question 3:
Clarify the meaning of the phrase “excluded from compliance evaluation” as used in Section 1.4 (“Additional Compliance Information”) of Part D of BAL-002-0 and for purposes of the preceding statements, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), does BAL-002-0 require ACE to be recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).
Response 3:
As discussed in the response to Question 1, the exclusion from compliance evaluation does not apply to all Disturbances that exceed the most severe single Contingency. Measure M1 of BAL-002-0 details the calculation of the percentage recovery for all Disturbances greater than or equal to 80% of the magnitude of the Balancing Authority’s or Reserve Sharing Group’s most severe single contingency loss. In addition to describing the calculation, the measure indicates that there will be a calculation of average percent recovery for Reportable Disturbances during a given quarter and a similar calculation for excludable Disturbances. Since calculation of both metrics is described in Measure M1, the phrase “excluded from compliance evaluation” indicates that the specified disturbances shall not be included in the calculation of “average percent recovery for Reportable Disturbances,” but will be included in the “average percent recovery for excludable Disturbances,” as specified in Measure M1. As indicated in Section D.1, compliance with the DCS will be measured on a percentage basis using these measures. While an entity’s average percent recovery for Reportable Disturbances may be calculated as 100%, BAL-002-0 Requirement R3 still requires a Balancing Authority or Reserve Sharing Group to “activate sufficient contingency reserves to comply with the DCS.” The Compliance Enforcement Authority, when verifying compliance with BAL-002-0, will be taking numerous factors into account, including whether or not the Balancing Authority or Reserve Sharing Group carried at least enough Contingency Reserve to cover the most severe single contingency. However, the determination of whether or not a violation of the standard has occurred rests with the Compliance Enforcement Authority. To the extent explicit limits are desired, they must be clearly specified in the requirements of the standard.

NERC
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RELIABILITY CORPORATION

Standards Announcement

Initial Ballot Window Open
February 15–26, 2010

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2009-19: Interpretation of BAL-002-0 for the Northwest Power Pool Reserve Sharing Group
An initial ballot window for an interpretation of standard BAL-002-0 — Disturbance Control Performance, Requirements R4 and R5, for the Northwest Power Pool Reserve Sharing Group is now open **until 8 p.m. EST on February 26, 2010**.

Instructions
Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Next Steps
Voting results will be posted and announced after the ballot window closes.

Project Background
The Northwest Power Pool Reserve Sharing Group requested clarification of language related to contingencies excluded from compliance evaluation.

The request and interpretation can be found on the project page:
http://www.nerc.com/filez/standards/Project2009-19_Interpretation_BAL-002-0_NWPP.html

Standards Development Process
The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

*For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.*

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Ballot Pool and Pre-ballot Window
January 15–February 15, 2010

Now available at: https://standards.nerc.net/BallotPool.aspx

Project 2009-19: Interpretation of BAL-002-0 for the Northwest Power Pool Reserve Sharing Group (NWPP RSG)

An interpretation of standard BAL-002-0 — Disturbance Control Performance, Requirements R4 and R5, for the Northwest Power Pool Reserve Sharing Group is posted for a 30-day pre-ballot review. Registered Ballot Body members may join the ballot pool to be eligible to vote on this interpretation **until 8 a.m. EST on February 15, 2010**.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2009-19_RFI_NWPPRSG_in@nerc.com.

Next Steps

Voting will begin shortly after the pre-ballot review closes.

Project Background

The Northwest Power Pool Reserve Sharing Group requested clarification of language related to contingencies excluded from compliance evaluation.

The request and interpretation can be found on the project page:
http://www.nerc.com/filez/standards/Project2009-19_Interpretation_BAL-002-0_NWPP.html

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For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Initial Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Project 2009-19: Interpretation of BAL-002-0 for the Northwest Power Pool Reserve Sharing Group (NWPP RSG)

The initial ballot for an interpretation of standard BAL-002-0 — Disturbance Control Performance, Requirements R4 and R5, for the Northwest Power Pool Reserve Sharing Group ended on February 26, 2010.

Ballot Results

Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 89.83%
Approval: 48.60%

Since at least one negative ballot included a comment, these results are not final. A second (or recirculation) ballot must be conducted. Ballot criteria are listed at the end of the announcement.

Next Steps

As part of the recirculation ballot process, the drafting team must draft and post responses to voter comments. The drafting team will also determine whether or not to make revisions to the balloted item(s). Should the team decide to make revisions, the revised item(s) will return to the initial ballot phase.

Project Background

The Northwest Power Pool Reserve Sharing Group requested clarification of language related to contingencies excluded from compliance evaluation.

The request and interpretation can be found on the project page:
http://www.nerc.com/filez/standards/Project2009-19_Interpretation_BAL-002-0_NWPP.html

Standards Development Process

The *Reliability Standards Development Procedure* contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

Ballot Criteria

Approval requires both a (1) quorum, which is established by at least 75% of the members of the ballot pool for submitting either an affirmative vote, a negative vote, or an abstention, and (2) A two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and nonresponses. If there are no negative votes with reasons from the first ballot, the results of the first ballot shall stand. If, however, one or more members submit negative votes with reasons, a second ballot shall be conducted.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Ballot Results	
Ballot Name:	Project 2009-19 - Interpretation - BAL-002-0 Northwest Power Pool RSG_in
Ballot Period:	2/15/2010 - 2/26/2010
Ballot Type:	Initial
Total # Votes:	212
Total Ballot Pool:	236
Quorum:	**89.83 % The Quorum has been reached**
Weighted Segment Vote:	48.60 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	61	1	26	0.491	27	0.509	4	4
2 - Segment 2.	12	1	6	0.6	4	0.4	0	2
3 - Segment 3.	54	1	27	0.587	19	0.413	4	4
4 - Segment 4.	15	1	5	0.385	8	0.615	2	0
5 - Segment 5.	43	1	16	0.485	17	0.515	5	5
6 - Segment 6.	33	1	10	0.4	15	0.6	2	6
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	6	0.4	2	0.2	2	0.2	0	2
9 - Segment 9.	4	0.3	1	0.1	2	0.2	1	0
10 - Segment 10.	8	0.6	3	0.3	3	0.3	1	1
Totals	**236**	**7.3**	**96**	**3.548**	**97**	**3.752**	**19**	**24**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott Kinney	Negative	View
1	BC Transmission Corporation	Gordon Rawlings	Negative	View
1	Beaches Energy Services	Joseph S. Stonecipher	Negative	View
1	Black Hills Corp	Eric Egge		

1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	Central Maine Power Company	Brian Conroy	Affirmative	
1	City of Vero Beach	Randall McCamish	Negative	View
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils		
1	E.ON U.S. LLC	Larry Monday	Abstain	
1	East Kentucky Power Coop.	George S. Carruba		
1	Empire District Electric Co.	Ralph Frederick Meyer	Negative	View
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg	Negative	View
1	ITC Transmission	Elizabeth Howell	Abstain	
1	JEA	Ted E Hobson	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Affirmative	
1	Lakeland Electric	Larry E Watt	Negative	View
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Long Island Power Authority	Jonathan Appelbaum	Affirmative	
1	Manitoba Hydro	Michelle Rheault	Negative	View
1	MEAG Power	Danny Dees	Negative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	National Grid	Saurabh Saksena		
1	New York State Electric & Gas Corp.	Henry G. Masti	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Negative	View
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Lawrence R. Larson	Negative	
1	PacifiCorp	Mark Sampson	Negative	View
1	Potomac Electric Power Co.	Richard J. Kafka	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	Progress Energy Carolinas	Sammy Roberts	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Catherine Koch	Negative	View
1	Sacramento Municipal Utility District	Tim Kelley	Negative	
1	Salt River Project	Robert Kondziolka	Negative	View
1	Santee Cooper	Terry L. Blackwell	Negative	View
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Negative	View
1	Sierra Pacific Power Co.	Richard Salgo	Negative	View
1	South Texas Electric Cooperative	Richard McLeon	Affirmative	
1	Southern California Edison Co.	Dana Cabbell	Affirmative	
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Abstain	
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Tampa Electric Co.	Thomas J. Szelistowski	Negative	
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Tri-State G & T Association Inc.	Keith V. Carman	Negative	View
1	Westar Energy	Allen Klassen	Negative	
1	Western Area Power Administration	Brandy A Dunn	Negative	View
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	View
2	Alberta Electric System Operator	Jason L. Murray	Negative	View
2	BC Transmission Corporation	Faramarz Amjadi	Negative	
2	California ISO	Timothy VanBlaricom	Affirmative	View
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Negative	View
2	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Jason L Marshall	Negative	View
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	Tom Bowe		
2	Southwest Power Pool	Charles H Yeung		
3	Alabama Power Company	Bobby Kerley	Affirmative	

3	American Electric Power	Raj Rana	Affirmative	
3	Arizona Public Service Co.	Thomas R. Glock		
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Black Hills Power	Andy Butcher	Negative	
3	Blue Ridge Power Agency	Duane S. Dahlquist	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Constellation Energy	Carolyn Ingersoll	Negative	View
3	Consumers Energy	David A. Lapinski	Affirmative	
3	Cowlitz County PUD	Russell A Noble		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources, Inc.	Jalal (John) Babik	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	View
3	Entergy Services, Inc.	Matt Wolf	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Gulf Power Company	Gwen S Frazier	Affirmative	
3	Hydro One Networks, Inc.	Michael D. Penstone	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	Manitoba Hydro	Greg C Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Affirmative	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	PacifiCorp	John Apperson	Negative	View
3	Platte River Power Authority	Terry L Baker	Negative	View
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Negative	View
3	Public Utility District No. 2 of Grant County	Greg Lange	Negative	View
3	Sacramento Municipal Utility District	James Leigh-Kendall	Negative	View
3	Salt River Project	John T. Underhill	Negative	View
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Negative	View
3	Seattle City Light	Dana Wheelock	Negative	View
3	South Carolina Electric & Gas Co.	Hubert C. Young	Affirmative	
3	Southern California Edison Co.	David Schiada		
3	Tampa Electric Co.	Ronald L Donahey	Negative	View
3	Turlock Irrigation District	Casey Hashimoto	Negative	
3	Wisconsin Electric Power Marketing	James R. Keller	Negative	View
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Negative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Negative	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Madison Gas and Electric Co.	Joseph G. DePoorter	Negative	View
4	Northern California Power Agency	Fred E. Young	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Abstain	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Negative	View
4	Sacramento Municipal Utility District	Mike Ramirez	Negative	View
4	Seattle City Light	Hao Li	Negative	View

4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Negative	View
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer		
5	Avista Corp.	Edward F. Groce	Negative	View
5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	Chelan County Public Utility District #1	John Yale	Negative	
5	City of Tallahassee	Alan Gale	Affirmative	
5	Consolidated Edison Co. of New York	Edwin E Thompson	Affirmative	
5	Consumers Energy	James B Lewis	Affirmative	
5	Dairyland Power Coop.	Warren Schaefer	Affirmative	
5	Detroit Edison Company	Ronald W. Bauer	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Robert Smith	Negative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	JEA	Donald Gilbert	Affirmative	View
5	Kansas City Power & Light Co.	Scott Heidtbrink	Negative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lincoln Electric System	Dennis Florom	Negative	View
5	Louisville Gas and Electric Co.	Charlie Martin	Abstain	
5	Manitoba Hydro	Mark Aikens	Negative	View
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Affirmative	
5	Northern States Power Co.	Liam Noailles	Negative	View
5	Orlando Utilities Commission	Richard Kinas		
5	PacifiCorp	Sandra L. Shaffer	Negative	View
5	Portland General Electric Co.	Gary L Tingley	Negative	
5	PPL Generation LLC	Mark A. Heimbach	Negative	View
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	David Murray	Affirmative	
5	Reedy Creek Energy Services	Bernie Budnik		
5	RRI Energy	Thomas J. Bradish	Negative	View
5	Sacramento Municipal Utility District	Bethany Wright	Negative	View
5	Salt River Project	Glen Reeves	Negative	View
5	Seattle City Light	Michael J. Haynes	Negative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	South California Edison Company	Ahmad Sanati		
5	South Carolina Electric & Gas Co.	Richard Jones	Abstain	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	U.S. Army Corps of Engineers Northwestern Division	Karl Bryan	Abstain	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Electric Power Co.	Linda Horn	Negative	View
5	Wisconsin Public Service Corp.	Leonard Rentmeester		
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Black Hills Corp	Tyson Taylor	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	View
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Chris Lyons	Negative	
6	Dominion Resources, Inc.	Louis S Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager	Negative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Eugene Water & Electric Board	Daniel Mark Bedbury	Negative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell		
6	Kansas City Power & Light Co.	Thomas Saitta	Affirmative	
6	Lakeland Electric	Paul Shipps	Negative	View
6	Louisville Gas and Electric Co.	Daryn Barker	Abstain	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	New York Power Authority	Thomas Papadopoulos		
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Negative	
6	PacifiCorp	Gregory D Maxfield	Negative	View
6	Portland General Electric Co.	John Jamieson	Negative	
6	PP&L, Inc.	Thomas Hyzinski	Negative	View

6	Progress Energy	James Eckelkamp	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson		
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Negative	View
6	RRI Energy	Trent Carlson		
6	Salt River Project	Mike Hummel	Negative	View
6	Santee Cooper	Suzanne Ritter	Negative	View
6	Seattle City Light	Dennis Sismaet	Negative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Affirmative	
6	Southern California Edison Co.	Marcus V Lotto		
6	SunGard Data Systems	Christopher K Heisler		
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8	Edward C Stein	Edward C Stein		
8	James A Maenner	James A Maenner	Negative	View
8	JDRJC Associates	Jim D. Cyrulewski	Negative	
8	Power Energy Group LLC	Peggy Abbadini		
8	Roger C Zaklukiewicz	Roger C Zaklukiewicz	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	California Energy Commission	William Mitchell Chamberlain	Negative	View
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	Maine Public Utilities Commission	Jacob A McDermott	Abstain	
9	Oregon Public Utility Commission	Jerome Murray	Negative	View
10	Electric Reliability Council of Texas, Inc.	Kent Saathoff	Negative	View
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Dan R. Schoenecker	Negative	View
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Jacquie Smith	Abstain	
10	SERC Reliability Corporation	Carter B Edge		
10	Western Electricity Coordinating Council	Louise McCarren	Negative	View

Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard
Date submitted: September 2, 2009
Date accepted: September 2, 2009
Contact information for person requesting the interpretation:
Name: Northwest Power Pool Reserve Sharing Group, in care of Jerry Rust, Agent
Organization: Northwest Power Pool Reserve Sharing Group
Telephone: 503-445-1074
E-mail: jerry.rust@nwpp.org
Identify the standard that needs clarification:
Standard Number (include version number): BAL-002-0
Standard Title: Disturbance Control Performance
Identify specifically what requirement needs clarification:

Requirement Number and Text of Requirement:

B. Requirements

***

R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.

R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.

***

R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. *** Compliance may be demonstrated by either

of the following two methods:

R.5.1 The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R.5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

* * *

D. **Compliance**

* * *

1.4 Additional Compliance Information

* * *

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Clarification needed:

The Northwest Power Pool Reserve Sharing Group respectfully requests clarification as to whether:

(1) although a Disturbance[1] that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), the Disturbance is excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group;

(2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve

[1] Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and

(3) the meaning of the phrase "excluded from compliance evaluation" as used in Section 1.4 ("Additional Compliance Information") of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Identify the material impact associated with this interpretation:

Clarification is needed to avoid applications of BAL-002-0 that would render the reserve requirement specified in R3.1 of BAL-002-0 (which calls for "enough Contingency Reserve to cover the most severe single Contingency") meaningless. The intent of BAL-002-0 is that all Contingencies greater than or equal to 80% of the most severe single Contingency constitute "Reportable Disturbances." *See* Section 1.4 of Part D of BAL-002-0 (where the "Additional Compliance Information" includes a definition of "Reportable Disturbance").

If a Balancing Authority were to experience a Contingency below the Reportable Disturbance level, it would be expected to recover ACE within 15 minutes, even though the literal words of R4 of BAL-002-0 do not say this. Conversely, if a Balancing Authority were to experience a Disturbance five times greater than its most severe single Contingency, it would be required to report this Disturbance, but would not be required to recover ACE within 15 minutes following a Disturbance of this magnitude.

Any other interpretation would result in treating BAL-002-0 as if it required Balancing Authorities and Reserve Sharing Groups to recover ACE (to zero or pre-Disturbance levels, as applicable) within the 15-minute Disturbance Recovery Period without regard to Disturbance magnitude. This is inconsistent with (a) the reserve requirement specified in R3.1 of BAL-002-0, (b) the text of Section 1.4 of Part D of BAL-002-0, and (c) the documented history of the development of BAL-002-0 (*see, e.g.,* Performance Standards Document, Version 3 (as accepted by NERC Resources Subcommittee on October 23, 2007), which provides in Section D, *Disturbance Control Standard, DCS*, that "An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.")

Furthermore, lack of clarity on the interpretation of this standard potentially has significant financial and operational impacts on all Balancing Authorities and Reserve Sharing Groups. If the standard is interpreted to require that ACE be returned to zero even for a Disturbance that exceeds the most severe single Contingency, a Balancing Authority could be required to take drastic operational actions, even when other measures of system reliability (voltage stability, normal frequency, operation within system operating limits, etc.) indicate otherwise.

Response:

The Balancing Authority Controls Standard Drafting Team was originally assigned to provide a response to the interpretation request. The original interpretation failed to achieve a two-thirds approval from the industry. NERC appointed a new IDT to develop this interpretation. On July 24, 2012, the team provided the following response to the questions raised:

Question 1: Although a Disturbance[2] that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group?

Response: The IDT agrees that the Disturbance would be excluded from compliance. The BAL-002 **Additional Compliance Information section** clearly states:

> Simultaneous Contingencies – Multiple contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, <u>the loss shall be reported</u>, <u>but excluded from compliance evaluation.</u>

For clarity the IDT would like to explain the Team's basis concerning some of the terminology used.

> **Most Severe Single Contingency (MSSC)** – this can be the loss of the BA's or RSG's single largest operating generator, or it can be a known common mode failure that causes more than one generator to fail when the contingency occurs; or it can be a firm transaction. Although Requirement R3.1 mandates an annual "review" that does not mean an annual value. Note that Requirement R3.1 determines a "prospective" MSSC. MSSC is a variable that the BA knows and operates to in real time. The largest operating generator is known and monitored by a BA. The largest known common mode failure is predefined for the BA; the largest single firm transaction is approved by the BA. Thus the BA knows its MSSC which can vary from hour to hour and minute to minute.
>
> To be clear a BA is responsible for the MSSC at all times (the MSSC value at any given time may be more or less than the annually identified prospective MSSC).
>
> An undefined "common mode" failure can occur but it is exempted from R4's requirement to meet the BA's or RSG's disturbance recovery criteria within the Disturbance Recovery Period. An undefined common mode failure (i.e. a disturbance that exceeds the MSSC) must be reported to allow the ERO to help ensure that it is not a continuing condition.

BAL-002 has two categories (1) Compliance and reporting (for Reportable Disturbances that must comply with the disturbance recovery criteria within the Disturbance Recovery Period) and (2) Reporting only (for specified disturbances and system conditions) events that are excluded from meeting Requirement R4.

---

[2] Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

The **Compliance and reporting category** is designed to be used to accumulate all DCS events that are subject to compliance to BAL-002 Requirement R4 (i.e. recover ACE within 15 minutes). These include all single assets as well as all pre-defined common mode failures. The standard originally created R_i (the average percent recovery for a Reportable Disturbance) as a measure of the quarterly compliance for Reportable Disturbances. Where all events greater than 80% were mandatory to report and those less than 80% were permitted to be reported (thus encouraging reporting smaller events).

The **Reporting only category** is designed to track multiple contingency events that are not subject to Requirement R4. This category is designed to ensure that common mode (single point of failures) events are not missed. Thus if two or more contingencies repeatedly occur, the expectation was that the ERO would have the information to alert the BA that the two contingencies must be considered as a single event and thus considered as the MSSC.

The **Performance Standard Reference document** initially included with the DCS standard does states "Where RSGs exist, the Regional Reliability Council is to decide either to report on a BA basis or an RSG basis. If an RSG has dynamic membership then… required …to report on a BA basis.

Question 2: With respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, does the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency apply both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance?

Response: Requirement R5 is directed to RSGs, where RSG is defined in the NERC Glossary as:

> A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.

The standard provides flexibility to BAs regarding the use or non-use of RSGs (Requirement R1.1). Requirement R2 affords the members flexibility in how they organize themselves.

Requirement R1.1 allows, at the option of a BA, or RSG to take on all or part of the responsibilities that BAL-002 places on a BA. However, Requirement R5 allows a BA to "call for activation" of reserves [aka dynamic allocation of membership] moreover, there is no ad hoc recognition of such an RSG's multiple contingencies since a contingency in one BA may or not be referred to the RSG, and the simultaneous contingency in another BA is unknown.

The Technical Document does allow for a pre-acknowledged RSG to report on a composite basis. It can be interpreted that such a pre-acknowledged RSG entity assumes all of the obligations and rights afforded to a single BA and in that case such an RSG would be afforded the same Exclusions as the Exclusions afforded a BA.

In summary, the interpretation is as follows:

- The Standard was written to provide pre-acknowledged RSGs the same considerations as a single BA for purposes of exclusions from DCS compliance evaluation. Thus for a pre-acknowledged RSG the exclusion rules would be used in the same manner as they would be used for a single BA. This applies to both multiple contingencies occurring within one minute or less of each other being treated as a single Contingency and to Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period.

The standard, while recognizing dynamically allocated RSGs, does NOT provide the members of dynamically allocated RSGs exclusions from DCS compliance evaluation on an RSG basis. For members of dynamically allocated RSGs, the exclusions are provided only on a member BA by member BA basis.

Question 3: Clarify the meaning of the phrase "excluded from compliance evaluation" as used in Section 1.4 ("Additional Compliance Information") of Part D of BAL-002-0 and for purposes of the preceding statements, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), does BAL-002-0 require ACE to be recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Response: The **Additional Compliance Information section** clearly states:

Simultaneous contingencies – Multiple contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the Most Severe Single Contingency, <u>the loss shall be reported</u>, <u>but excluded from compliance evaluation.</u>

Although Requirement R3 does mandate that a BA or RSG activate sufficient Contingency Reserves to comply with DCS for every Reportable Disturbance, there is no requirement to comply with or even report disturbances that are below the Reportable Disturbance level. The averaging obligation does incent calculation and reporting of such lesser events.

If a Balancing Authority were to experience a Disturbance five times greater than its most severe single Contingency, it would be required to report this Disturbance, but would not be required to recover ACE within 15 minutes following a Disturbance of this magnitude.

An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency. Any other interpretation would result in treating BAL-002-0 as if it required Balancing Authorities and Reserve Sharing Groups to recover ACE (to zero or pre-Disturbance levels, as applicable) within the 15-minute Disturbance Recovery Period without regard to Disturbance magnitude. This is inconsistent with (a) the reserve requirement specified in R3.1 of BAL-002-0, (b) the text of Section 1.4 of Part D of BAL-002-0, and (c) the documented history of the development of BAL-002-0 (*see, e.g.,* Performance Standards Document, Version 3 (as accepted by NERC Resources Subcommittee on October 23, 2007), which provides in Section D, *Disturbance Control Standard, DCS*, that "An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.")

Unofficial Comment Form

Project 2009-19 – Interpretation of BAL-002-0 for NWPP

Please **DO NOT** use this form to submit comments. Please use the electronic form located at the link below to submit comments on the Interpretation of BAL-002-0 (R4, R5, and Section D 1.4) for the Northwest Power Pool Reserve Sharing Group. The electronic comment form must be completed by 8 p.m. ET **September 4, 2012.**

http://www.nerc.com/filez/standards/Project2009-19_Interpretation_BAL-002-0_NWPP.html

If you have questions please contact Darrel Richardson at darrel.richardson@nerc.net or by telephone at (609) 613-1848.

Background Information

This posting is soliciting formal comment.

This Request for Interpretation (RFI) was submitted by the Northwest Power Pool Reserve Sharing Group (NWPP) to provide clarity in three specific areas of BAL-002-0 Disturbance Control Performance. The specific areas NWPP is requesting clarification on are; 1) although a Disturbance that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group; 2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and 3) the meaning of the phrase “excluded from compliance evaluation” as used in Section 1.4 (“Additional Compliance Information”) of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

NWPP notes that without further clarity this standard potentially has significant financial and operational impacts on all Balancing Authorities and Reserve Sharing Groups. If the standard is interpreted to require that ACE be returned to zero even for a Disturbance that exceeds the most severe single Contingency, a Balancing Authority could be required to take drastic operational actions, even when other measures of system reliability (voltage stability, normal frequency, operation within system operating limits, etc.) indicate otherwise.

The original interpretation failed to achieve a two-thirds approval from the industry. The original Interpretation Drafting Team (IDT) did not believe that an interpretation could be developed that would provide sufficient clarity on the requestors points of interest without the using the “Additional Compliance Information” elements within the standard. Initially, the IDT believed that the “Additional Compliance Information” section could not be used to interpret the requirements of a standard. The Standards Committee (SC) agreed and the interpretation was tabled. The NERC BOT later ruled that the “Additional Compliance Information” elements should be recognized as part of the standard and that they could be utilized to provide guidance on the meaning of the requirements. The SC re-activated the project in May 2012. The IDT has reviewed the NWPP request and developed this interpretation pursuant to the NERC Guidelines for Interpretation Drafting Teams, which is available at:

http://www.nerc.com/files/Guidelines_for_Interpretation_Drafting_Teams_Approved_April_2011.pdf)

You do not have to answer all questions. Enter All Comments in Simple Text Format.

Please review the request for an interpretation, the associated standard, and the draft interpretation and then answer the following questions.

1. Do you agree with **Response 1** of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language.

   ☐ Yes
   ☐ No

   Comments:

2. Do you agree with **Response 2** of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language.

   ☐ Yes
   ☐ No

   Comments:

3. Do you agree with **Response 3** of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language.

   ☐ Yes
   ☐ No

   Comments:

Standards Announcement

Project 2009-19
Interpretation of BAL-002-0 - NWPP Reserve Sharing Group

Successive Ballot Window Open through 8 p.m. Tuesday, September 4, 2012

Now Available

A successive ballot for the Interpretation of BAL-002-0 - Disturbance Control Performance Requirements R4 and R5 for NWPP Reserve Sharing Group is open through **8 p.m. Eastern on Tuesday, September 4, 2012**.

Instructions

Members of the ballot pool associated with this project may log in and submit their vote for the interpretation by clicking here.

Please read carefully: All stakeholders with comments (both members of the ballot pool as well as other stakeholders, including groups such as trade associations and committees) must submit comments through the electronic comment form. During the ballot window, balloters who wish to submit comments with their ballot may no longer enter comments on the balloting screen, but may still enter the comments through the electronic comment form. Balloters who wish to express support for comments submitted by another entity or group will have an opportunity to enter that information and are not required to answer any other questions.

Next Steps

The drafting team will consider all comments received during the formal comment period and successive ballot and, if needed, make revisions to the interpretation. If the comments do not show the need for significant revisions, the standard will proceed to a recirculation ballot.

Background

Northwest Power Pool Reserve Sharing Group (NWPP) submitted a request for interpretation asking for clarification in three specific areas of BAL-002-0 Disturbance Control Performance. The specific areas NWPP is requesting clarification on are; 1) although a Disturbance that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group; 2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all

Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and 3) the meaning of the phrase "excluded from compliance evaluation" as used in Section 1.4 ("Additional Compliance Information") of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Additional information is available on the project page.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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Standards Announcement

Interpretation of BAL-002-0 for NWPP Reserve Sharing Group
Project 2009-19

Ballot Pool Forming:	July 25, 2012 – August 23, 2012
Formal Comment Period Open:	July 25, 2012 – September 4, 2012

Upcoming:

Successive Ballot	August 23, 2012 – September 4, 2012

Now Available

A formal comment period for the Interpretation of BAL-002-0 - Disturbance Control Performance Requirements R4 and R5 by NWPP Reserve Sharing Group is open through **8 p.m. Eastern on Tuesday, September 4, 2012** and a ballot pool is forming through **8 a.m. Eastern Thursday, August 23, 2012**.

Instructions for Joining Ballot Pool

Registered Ballot Body members must join the ballot pool to be eligible to vote in balloting of the Interpretation of BAL-002-0 Requirements R4 and R5 at Join Ballot Pool.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list servers." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list server.) The ballot pool list server for this ballot pool is:

Successive ballot: bp-2009-19_BAL-002_SB_in@nerc.com

The ballot pool is open **through 8 a.m. Eastern on Thursday, August 23, 2012.**

Instructions for Commenting

A formal comment period is open through **8 p.m. Eastern on Tuesday, September 4, 2012.** Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Please read carefully: All stakeholders with comments (both members of the ballot pool as well as other stakeholders, including groups such as trade associations and committees) must submit comments through the electronic comment form. During the ballot window, balloters who wish to submit comments with their ballot may no longer enter comments on the balloting screen, but may still enter the comments through the electronic comment form. Balloters who wish to express support for comments submitted by another entity or group will have an opportunity to enter that information on the electronic survey and are not required to answer any other questions.

Next Steps

A Successive ballot of the interpretation will be conducted beginning Thursday, August 23, 2012 through 8 p.m. Eastern on Tuesday, September 4, 2012.

Background

Northwest Power Pool Reserve Sharing Group (NWPP) submitted a request for interpretation asking for clarification in three specific areas of BAL-002-0 Disturbance Control Performance. The specific areas NWPP is requesting clarification on are; 1) although a Disturbance that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group; 2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and 3) the meaning of the phrase "excluded from compliance evaluation" as used in Section 1.4 ("Additional Compliance Information") of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Additional information is available on the [project page.](#)

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Standards Announcement

Project 2009-19 – Interpretation of BAL-002-0 - NWPP Reserve Sharing Group

Successive Ballot Results

Now Available

A successive ballot for the Interpretation of BAL-002-0 - Disturbance Control Performance Requirements R4 and R5 for NWPP Reserve Sharing Group concluded on Tuesday, September 4, 2012.

Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results.

Ballot Results
Quorum: 79.21%
Approval: 87.78%

Next Steps

The drafting team will consider all comments received during the formal comment period and successive ballot and, if needed, make revisions to the interpretation. If the comments do not show the need for significant revisions, the standard will proceed to a recirculation ballot.

Background

Northwest Power Pool Reserve Sharing Group (NWPP) submitted a request for interpretation asking for clarification in three specific areas of BAL-002-0 Disturbance Control Performance. The specific areas NWPP is requesting clarification on are; 1) although a Disturbance that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group; 2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and 3) the meaning of the phrase "excluded from compliance evaluation" as used in Section 1.4 ("Additional Compliance Information") of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

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Ballot Results	
Ballot Name:	Project 2009-19 Successive Ballot BAL-002 July 2012_in
Ballot Period:	8/23/2012 - 9/4/2012
Ballot Type:	Initial
Total # Votes:	282
Total Ballot Pool:	356
Quorum:	**79.21 % The Quorum has been reached**
Weighted Segment Vote:	87.78 %
Ballot Results:	**The drafting team will review comments received.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	94	1	54	0.794	14	0.206	8	18
2 - Segment 2.	10	0.9	8	0.8	1	0.1	0	1
3 - Segment 3.	81	1	48	0.857	8	0.143	6	19
4 - Segment 4.	25	1	14	0.933	1	0.067	4	6
5 - Segment 5.	75	1	45	0.938	3	0.063	8	19
6 - Segment 6.	52	1	31	0.886	4	0.114	9	8
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	10	0.6	6	0.6	0	0	1	3
9 - Segment 9.	2	0.2	2	0.2	0	0	0	0
10 - Segment 10.	7	0.6	4	0.4	2	0.2	1	0
Totals	**356**	**7.3**	**212**	**6.408**	**33**	**0.893**	**37**	**74**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Negative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Affirmative	

1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley		
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	El Paso Electric Company	Dennis Malone	Affirmative	
1	Entergy Transmission	Oliver A Burke		
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	Mike O'Neil		
1	FortisBC	Curtis Klashinsky		
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley		
1	M & A Electric Power Cooperative	William Price	Negative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Ryan Millard	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Progress Energy Carolinas	Brett A. Koelsch		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	

1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Negative	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Abstain	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Howell D Scott	Negative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	Turlock Irrigation District	Esteban Martinez	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Negative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Ken A Gardner	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach		
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk		
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Abstain	
3	El Paso Electric Company	Tracy Van Slyke	Affirmative	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power Corporation	Lee Schuster		
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	

3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	
3	Ocala Electric Utility	David Anderson		
3	Oklahoma Gas and Electric Co.	Gary Clear		
3	Orange and Rockland Utilities, Inc.	David Burke		
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Affirmative	
3	Pepco Holdings, Inc.	Mark R Jones		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 1 of Chelan County	Steve Wickel	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	
3	Snohomish County PUD No. 1	Mark Oens		
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	David B Coher		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Negative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Turlock Irrigation District	James Ramos	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney		
4	Fort Pierce Utilities Authority	Cairo Vanegas		
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Affirmative	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh		
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Abstain	

4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Turlock Irrigation District	Steven C Hill	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Negative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		
5	Calpine Corporation	Phillip Porter		
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty		
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Dairyland Power Coop.	Tommy Drea		
5	Deseret Power	Philip B Tice Jr	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Detroit Renewable Power	Marcus Ellis		
5	Duke Energy	Dale Q Goodwine	Negative	
5	El Paso Electric Company	David Hawkins	Affirmative	
5	Essential Power, LLC	Patrick Brown	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann		
5	Great River Energy	Preston L Walsh		
5	Hydro-Québec Production	Roger Dufresne		
5	Imperial Irrigation District	Marcela Y Caballero	Abstain	
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough		
5	Lakeland Electric	James M Howard		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	Proven Compliance Solutions	Mitchell E Needham	Abstain	
5	Public Utility District No. 1 of Chelan County	John Yale	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	

5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	Turlock Irrigation District	Marty Rojas	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Abstain	
5	Westar Energy	Bryan Taggart		
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Donald Schopp	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Negative	
6	El Paso Electric Company	Tony Soto	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery		
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley		
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	John Jamieson		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	Progress Energy	John T Sturgeon	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen		
6	Southern California Edison Company	Lujuanna Medina	Abstain	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	
6	Turlock Irrigation District	Amy Petersen	Affirmative	
6	Westar Energy	Grant L Wilkerson		

6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		James A Maenner		
8		Edward C Stein	Affirmative	
8	Ascendant Energy Services, LLC	Raymond Tran	Affirmative	
8	Energy Mark, Inc.	Howard F. Illian	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	Oregon Public Utility Commission	Jerome Murray	Affirmative	
10	Midwest Reliability Organization	William S Smith	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	
10	SERC Reliability Corporation	Carter B. Edge	Negative	
10	Southwest Power Pool RE	Emily Pennel	Abstain	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Atlanta Office: 3353 Peachtree Road, N.E. : Suite 600, North Tower : Atlanta, GA 30326
Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Name (17 Responses)
Organization (17 Responses)
Group Name (10 Responses)
Lead Contact (10 Responses)
Contact Organization (10 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. Please be sure to click on 'finish' to complete the submittal process. (0 Responses)
Comments (27 Responses)
Question 1 (23 Responses)
Question 1 Comments (23 Responses)
Question 2 (23 Responses)
Question 2 Comments (23 Responses)
Question 3 (22 Responses)
Question 3 Comments (23 Responses)

Individual
B
N
Company XYZ
Individual
Michael Falvo
Independent Electricity System Operator
Yes
We agree with the response. However, we do not agree with some of the details in the section that attempts to provide clarification, excerpt below: “Most Severe Single Contingency (MSSC) – this can be the loss of the BA’s or RSG’s single largest operating generator, or it can be a known common mode failure that causes more than one generator to fail when the contingency occurs; or it can be a firm transaction.” We do not agree the term “firm transaction”. The loss of or interruption to a transaction, regardless of its firmness, represents a loss of resource which may trigger the need to comply with the DCS requirement. In other words, a temporary deficiency in a BA’s resource has no distinction on whether it is caused by the loss/interruption to a firm transaction or a non-firm transaction. Further, the term “firm transaction” is subject to debate as to whether the firmness is in the energy component or in the transmission service component. If the proposed clarification is to be adopted by registered entities as a guideline for compliance (which this interpretation appears to be attempting to provide), then it can have a potential for opening up a reliability gap since a BA or an RSG may not respond to a resource contingency resulting from the loss or an interruption to a non-firm transaction (however the firmness is interpreted to be). We suggest to remove the word “firm” from the clarification section.
Yes
Yes
(1) We generally agree with the proposed interpretation. However, we are not sure if this request fits well into NERC’s criteria for acceptance as a valid request since it appears that the requester asks specifically on the compliance implications and compliance elements. We suggest the interpretation drafting team (IDT) to evaluate whether or not the request is a valid one that seeks clarity on the requirements, rather than on the compliance aspects of the standard/requirements. If the IDT does assess that the questions are addressing a compliance issue, then we suggest the IDT to bring this to the attention of the Standards Committee for a determination of the appropriate means to address the questions. (2) The IESO agrees with NERC’s interpretation of BAL-002. However, we believe additional discussion and thought need to be applied to other Standards to ensure that no gaps or overlaps exist in both task execution and Standard application. Different Standards obligate Reliability Entities to fulfill certain tasks as it pertains to balancing: conditions. This includes: • BAL- 002 outlines

obligations to balance following Reportable Disturbances; • EOP-002 outlines obligations to balance during Capacity and Energy Emergencies; and • TOP-001 outlines obligations to balance during System Emergencies. All of these Standards have similarities but need interpretation to ensure consistent application. These interpretations are based on an understanding of the NERC Functional Model and upon clear statements in the purpose and requirement sections in the Standards. We believe that the objective of each of the Standards list above must be clarified to reduce confusion and support consistent application.
Individual
Nazra Gladu
Manitoba Hydro
Yes
Yes
Yes
Group
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating Council
Yes
Yes
Yes
Individual
Thad Ness
American Electric Power
No
We do not understand the interpretation provided by the drafting team based on the requirements of BAL-002-0. As a result, we cannot endorse the interpretation provided.
No
We do not understand the interpretation provided by the drafting team based on the requirements of BAL-002-0. As a result, we cannot endorse the interpretation provided. For example, it is not clear to us exactly what “pre-acknowledged” or “dynamic” means in regards to Reserve Sharing Groups. These terms are not found anywhere within the standard itself, nor are they commonly used to describe or qualify Reserve Sharing Groups.
No
We do not understand the interpretation provided by the drafting team based on the requirements of BAL-002-0. As a result, we cannot endorse the interpretation provided.
Individual
Oliver Burke
Entergy Services, Inc.
Yes

Yes
Yes
Individual
John Appel
Public Utility District #1 of Chelan County
Chelan PUD supports the interpretation of BAL-002-0 on behalf of the NWPP.
Individual
Don Schmit
Nebraska Public Power District
Yes
The interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Yes
The interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Yes
The interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
Arizona Public Service Company
Yes
Yes
Yes
Individual
Carter Edge
SERC
No
The interpretations process is not an appropriate mechanism to address a compliance monitoring and enforcement issue. Further, the words in the requirements do not support the interpretation, no matter how much the interpretation reflects how the industry and ERO have historically approached the Disturbance Control Standard. The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Specifically, Requirement 1 requires each Balancing Authority to have access to and/or operate Contingency Reserve to respond to Disturbances. Prior to penalties and sanctions under Section 215, the consequence of failing DCS was to require an increase in contingency reserves. This is the “compliance evaluation” referred to under Section D. The expectation is that Balancing Areas respond to the loss of resources regardless of magnitude to restore ACE and minimize the risk to reliable operation of being “out of balance”. There was recognition, however, that interconnected operations increased the reliability of the grid by reducing the consequences of a single area being out of balance at any given time and thus allowed the collective greater utilization of installed capacity to

serve load rather than retain it as contingency reserves. Thus, the concept of “most severe single contingency” (MSSC) as a criterion against which to require additional contingency reserve was employed and for large contingencies may require more time to respond. Fifteen minutes is a "benchmark" time-frame that is reasonable to expect a Balancing Area to recover from a credible contingency. There is nothing magical about that time (it used to be 10 minutes), but the BA should not "lean" on the system longer than is necessary regardless of the magnitude. Performance outside this benchmark can only be determined by an inspection of the facts and circumstances of each instance. All Balancing Authorities and Reserve Sharing Groups are required to review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies. The NERC glossary defines Contingency as the “unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element”. Thus, the compliance action or inaction ("decline to pursue") with respect to the performance of an entity against the stated requirements in the standard is a matter of the CMEP and should not be addressed through the standards interpretations process. Compliance activity should be based on the facts and circumstances of each case measured against the performance requirements of the standard. Standards (including interpretations) are for describing the behaviors and actions of registered entities necessary for the reliable planning and operation of the bulk power system not the Compliance Enforcement Authority. Informed and expert discretion rather than this interpretation (which requires inaction) is a better answer for the Reliability Assurer. Further, ALR 2-5 has a stated purpose as a measure of how much risk a system is exposed to for extreme or unusual contingencies (Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation). The results of ALR 2-5 are expected to help validate current contingency reserve requirements and document how often these “extreme or unusual” contingencies occur. These activities should continue.
No
See answer to question #1.
No
See Response to question #1.
Group
ISO-RTO Standards Review Committee
Terry Bilke
MISO
Yes
We agree with the response. However, we do not agree with some of the details in the section that attempts to provide clarification, excerpt below: “Most Severe Single Contingency (MSSC) – this can be the loss of the BA’s or RSG’s single largest operating generator, or it can be a known common mode failure that causes more than one generator to fail when the contingency occurs; or it can be a firm transaction.” We do not agree the term “firm transaction”. The loss of or interruption to a transaction, regardless of its firmness, represents a loss of resource which may trigger the need to comply with the DCS requirement. In other words, a temporary deficiency in a BA’s resource has no distinction on whether it is caused by the loss/interruption to a firm transaction or a non-firm transaction. Further, the term “firm transaction” is subject to debate as to whether the firmness is in the energy component or in the transmission service component. If the proposed clarification is to be adopted by registered entities as a guideline for compliance (which this interpretation appears to be attempting to provide), then it can have a potential for opening up a reliability gap since a BA or an RSG may not respond to a resource contingency resulting from the loss or an interruption to a non-firm transaction (however the firmness is interpreted to be). We suggest to remove the word “firm” from the clarification section.
Yes
Yes
It might be clearer if the reponse added the phrase [of the Disturbance Control Standard] after “loss

shall be reported, but excluded from compliance evaluation". Following a large event, the BA would still be accountable for other standards (e.g. IRO standards)
Group
ACES Power Marketing Standards Collaborators
Ben Engelby
ACES Power Marketing
Yes
We conceptually agree with the position of the interpretation. However, we believe that thecurrent response expands issues that were not raised in the original question. One example is that the "MSSC value at any given time may be more or less than the annually identified prospective MSSC" is contradictory to the interpretation. How could the MSSC value could ever be higher than the list of candidate MSSCs identified in the annual review. Also, in the "reporting only" category in response 1, the IDT incorrectly characterizes that the ERO would have authority or the information to alert the BA that two (or more) contingencies must be considered as a single event and thus considered as the MSSC. The ERO does not determine the MSSC, the BA or RSG makes that determination. For simplicity and clarity, we recommend that the interpretation state: Disturbances greater than MSSC are excluded from the compliance calculation, based on the additional compliance information section of BAL-002-0. The IDT could strike everything following this statement from the interpretation and would convey the same message in a more clear and concise manner.
Yes
We largely agree with the interpretation. However, we want to point out that the concept of pre-acknowledged RSGs have disincentivized Adjacent Balancing Authorities (not in a pre-acknowledged RSG) to provide reserves in less than 10 minutes even if they are capable. If an Adjacent Balancing Authority provides emeregency energy in an amount that exceeds its own MSSC with a ramp less than 10 minutes and fails to recover its ACE from within 15 minute of the initial disturbance, the Adjacent BA may be found non-compliant despite the fact the it provided the appropriate reliability assistance. Compliance should not disincentivize actions that ensure reliability.
Yes
We agree for the most part with this interpretation. However, we do have a few points we would like to address. We recommend striking the entire second paragraph because it is irrelevant. The standard does not say comply with DCS "for every reportable disturbance." The key is whether a BA is required to recover ACE within 15 minutes for contingencies greater than MSSC, and that answer is no. The IDT should keep the interperpratation simple. A recommendation for wording the interpretation: A BA is not required to recover ACE within 15 minutes for contingencies greater than MSSC, as stated in section 1.4 ("Additional Compliance Information"). We recommend that the IDT reduce the amount detail in the rationale and focus on the three questions in the request. The current draft of the interpretation is wordy, confusing and provides excessive details instead of answering the questions that were asked. Also, the IDT did not state that this interpretation would apply to BAL-002-1, which has been enforceable since 4/1/2012. If NERC is going to continue with the interpretation process for BAL-002, the interpretation should apply to both versions of the standard. Finally, we encourage NERC to consolidate standard projects. There are currently 10 standard projects under development for BAL standards. NERC should consider either a consolidation to a reduced amount of BAL projects or even a single project to cover all BAL issues in order to avoid duplication, overlap, inefficient use of resources and confusion.
Group
El Paso Electric
Pablo Oñate
El Paso Electric
Yes
El Paso Electric (EPE) generally supports the first interpretation proposed by the IDT but is concerned with the language immediately following "To be clear…" because it does not acknowledge the fact that many BAs have placed responsibility in the hands of a RSG. The interpretation states that "…a BA is

responsible for the MSSC at all times...". EPE believes that this responsibility should be shared with a RSG, where appropriate. EPE would be more comfortable with an interpretation that read "To be clear a BA or RSG, as applicable, is responsible for the MSSC at all times..."
Yes
EPE generally supports the second interpretation by the IDT but requests that IDT clarify the scope of compliance evaluations for BAs who are part of a RSG and experienced a reportable event, without regard to whether any individual BA member of the RSG requested assistance. If a RSG determines that the group as a whole complied with CPS then there should be no need for any individual BA review or reporting under R5, without regard to whether the BA called for reserve activation from other RSG members, or not. The interpretation should include this clarification.
Yes
No Comment.
Individual
x
x
Individual
linda Horn
Wisconsin Electric Power Company
We are supporting the comments of MISO.
Group
Duke Energy
Greg Rowland
Duke Energy
Yes
We suggest that there should be a SAR to define the terms MSSC and “excludable disturbance” add them to the NERC Glossary.
No
It’s not clear what the drafting team is saying, particularly the reference to “dynamic allocation of membership”. What’s the difference between pre-acknowledged RSGs and dynamically allocated RSGs, and why are the exclusion rules different?
No
It’s not clear what the drafting team is saying. Does “excluded from compliance evaluation” mean that R4 does not apply to Disturbances that exceed the MSSC for a BA or RSG? Does it matter if the RSG is pre-acknowledged or dynamically allocated? The drafting team’s response to Question 2 seems to indicate that it does matter. We agree that DCS is not applicable for losses greater than the MSSC, and also that DCS compliance is not required for losses less than 80% of the MSSC (or lower if a lower threshold is adopted for DCS reporting). This interpretation is performed on BAL-002-0, but the current effective standard is BAL-002-1 as of 4-1-2012. If the interpretation is approved, what is its applicability to BAL-002-1? Under BAL-002-0 the default Disturbance Recovery Period could be adjusted to better suit the needs of an Interconnection (R4.2) and the default Contingency Reserve Restoration Period could be adjusted to better suit the reliability targets of the Interconnection (R6.2), both based on analysis approved by the NERC Operating Committee. This has been deleted from both requirements in BAL-002-1.
Group
Associated Electric Cooperative Inc - JRO00088
David Dockery
Associated Electric Cooperative Inc
No
Remove: The final paragraph beginning with "The Performance Standard Reference document initially

included..." Rationale: A text-search of BAL-002-0, downloaded from the NERC website, fails to yield any instances of the word “dynamic”, meaning that it appears nowhere within the four-corners of the BAL-002-0 Standard. Responsible Entities are subject only to the Standard’s requirements as written and within its Effective Dates 4/1/2005 to 8/5/2010, when BAL-002-1 effectively replaced it. NERC’s BOT Approved August 2, 2006 filing with The Commission appears to contain the oldest copy of FERC approved NERC Glossary of Terms Used in Reliability Standards. It contains no instances of the word “dynamic” that correspond in any way to Reserve Sharing Group membership, although “Reserve Sharing Group” and “Reportable Disturbance” are defined within that document. Although the SDT asserts the augmented concept of RSG dynamic membership, those references within this interpretation should be stricken because the “dynamic membership” concept clearly does not exist within the “four-corners of the Standard” which was balloted and approved by industry stakeholders. Instead BAL-002-0 wording indicates that each RSG can establish its own guidance, necessary to comply with the Requirements. Requirement R2 provides each Reserve Sharing Group the flexibility concerning its policies governing how it collectively fulfills its responsibility to meet Requirements R3, R4, R5 and R6. However Requirement R5’s parenthetical does appear to provide some governance concerning a BA's reporting within a Reserve Sharing Group when they do not call for reserve activation from its other members, that they are subject to individually reporting their performance in responding to that event. (In either case of reporting per R5 parenthetical, the RSG’s collectively-committed units’ spinning-mass and short-term governor response would have fulfilled the reliability objective of this Standard, unless the Reportable Disturbance’s magnitude was much greater than anticipated by the RSG in its entirety.)
No
Replace: The entire answer. With: “Yes.” Rationale: In our opinion, the IDT failed to answer Question #2, which could have been answered with a simple “Yes”. Instead, they appear to attempt legislating upon particulars of how all RSGs should structure portions of their policies under R2, by again referring to the concept of “dynamic membership”. Our understanding is that such expansion of Standard governance can only be done under SDT effort and subsequent industry approval through the ballot process. (See AECI’s earlier response to Question 1 above.)
Yes
We agree with this summary determination. In addition, the August 2, 2006 NERC BOT approved, and subsequently FERC accepted Glossary definition for Reportable Disturbance clearly specified that the definition “not be retroactively adjusted in response to observed performance”, adding weight to this drafting-team’s response to Question 3. (FERC_Filing_Proposed_Reliability_Standards_Docket_RM06-16-000.pdf)
Individual
Greg Travis
Idaho Power Co.
Yes
Yes
Yes
Group
Bonneville Power Administration
Chris Higgins
Transmission Reliability Program
Yes
Yes

Yes
BPA is in support of BAL-002-0 Interpretation and has no comments or concerns at this time.
Group
SPP Standards Review Group
Robert Rhodes
Southwest Power Pool
Yes
This interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Yes
Again, this interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Yes
Again, this interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Yes
Yes
Yes
Individual
Anthony Jablonski
RelliabilityFirst
No
ReliabilityFirst votes in the Negative for the Interpretation of BAL-002 since ReliabilityFirst believes the drafted interpretation to Question 1 incorrectly expands on the language in Requirement R4 and incorrectly attempts to explain how to comply with the Requirement. If a reportable disturbance occurs (i.e. contingencies that are greater than or equal to 80% of the most severe single Contingency) and is greater than the most severe single Contingency, ReliabilityFirst questions why an entity would not be required to meet the Disturbance Recovery Criterion. Nowhere within the requirements are there exceptions for Reportable Disturbance greater than the most severe single Contingency. Based on R4, the applicable entity "…shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances". For example, if an entity failed to meet the meet the Disturbance Recovery Criterion for a disturbance equaling 110% of their most severe single Contingency, they would potentially be found non-compliant. In addition, ReliabilityFirst does not believe the quasi definition of "Simultaneous Contingencies" within the "Additional Compliance Information" is not enforceable since it is not a Reliability Requirement, and is not even a NERC Defined term.
Yes
ReliabilityFirst disagrees with the drafted interpretation. Regardless of the references to outside sources (the reserve requirement specified in R3.1 of BAL-002-0, the text of Section 1.4 of Part D of BAL-002-0, and the documented history of the development of BAL-002-0), compliance is to be assessed on a requirement by requirement basis. Requirement R4 requires that an applicable entity "…shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of

Reportable Disturbances". Clearly, there is no exception listed within the requirements for Reportable Disturbances greater that the most severe single Contingency.
Individual
Maggy Powell
Exelon Corporation
Yes
Yes
No
Response 3 of the interpretation that requests clarification on the phrase "excluded from compliance evaluation" could be clearer. The first portion of the response gives the impression that the IDT is of the opinion that the obligation to comply with the DCS extends to events larger in magnitude than the MSSC. The paragraphs that follow go on to clarify that an event greater than the MSSC would not be required to recover ACE within 15 minutes, making compliance with the DCS not mandated in these instances. The latter (disturbances exceeding the MSSC being excluded from DCS compliance and 15 minute recovery) is consistent with practice and in line with the interpretation indicated by the NWPP. In order to more fully clarify the interpretation, the IDT should make clear that compliance with the DCS is not mandated for disturbances exceeding the MSSC.
Group
SERC Operating Committee Standards Review Team
Gerald Beckerle
Ameren
Yes
The SERC OC Standards Review Group gladly presents the following comments. The SERC OC Standards Review Group agrees only with the interpretation portion of the response. The Group strongly disagrees there is a need for the additional explanation of the interpretation. The explanation presents more confusion and questions around the Standard. The simple interpretation is very clear and concise.
No
The SERC OC Standards Review Group feels the interpretation and clarification are both very confusing, thus raising numerous other questions. The use of the words "pre-acknowledged RSGS" and "dynamic allocated RSGS" appear to be new terms introduced in the response. Also, a reference to a Technical Document is made in the response. The Group is unsure of what Technical Document the IDT is referring. Nor does the Group understand if such reference to the Technical Document is an agreement with such document by the IDT or if the Technical Document is referenced as to be included in the response and subject to being opened and the processes and procedures of such document being made part of a compliance audit.
Yes
NONE
Individual
Brent Ingebrigtson
LG&E and KU Services Company
No
The IDT's explanation of MSSC may be uneccessary and confusing, especially statements such as: "MSSC is a variable that the BA knows and operates to in real time." "Thus the BA knows its MSSC which can vary from hour to hour and minute to minute." "To be clear a BA is responsible for the MSSC at all times (the MSSC value at any given time may be more or less than the annually identified prospective MSSC)." In the absence of an identifiable/specific reason, which is recognized by the BA

in advance, the real-time MSSC should not exceed the prospective MSSC. Unless such an abnormal situation exists, all evaluations of DCS compliance must be based on the prospective MSSC value. The IDT needs to be very clear with any language suggesting that the real-time MSSC can exceed the planned/recognized/"prospective" MSSC. If a disturbance exceeds the planned/recognized/"prospective" MSSC value, it is outside the definition of MSSC and should not be subject to compliance evaluation. The requirement for a prospective MSSC is for the MSSC be used for planning purposes, not for real-time operations, even though it is used in such operations. MSSC is not a defined term in the NERC Glossary but work is in progress under NERC Project 2010-14.1 to develop a definition of MSSC. Therefore, it would not be in the best interest of the IDT in providing this interpretation to attempt to describe or define MSSC. LGE and KU Services recommends all language related to the IDT's explanation of MSSC be deleted from Response 1. Also, the language explaining the "Compliance and reporting category" and "Reporting only category" appears to be outside the inquiry of Question 1 and is suggested for deletion. LGE and KU Services suggests Response 1 be reduced to simply the first sentence of the response as it clearly answers Question 1: "The IDT agrees that the Disturbance would be excluded from compliance."
No
The meaning and use of the adjectives "pre-acknowledged" and "dynamically allocated" in description of RSG in Response 2 seem to be uneccessary, confusing and beyond the scope of Question 2. As stated in Response 2, there is a NERC Glossary definition of RSG and that is the subject of Question 2 – not the applicability of R5 to organizational variations of RSGs. The IDT has referenced a "Technical Document" that has not been included in the posting. The content therefore of the Technical Document is unknown. LGE and KU Services suggests Response 2 be reduced to only the language used in the "In summary,…." portion of the response as it clearly answers Question 2, edited as follows: "The Standard was written to provide RSGs the same considerations as a single BA for purposes of exclusions from DCS compliance evaluation. Thus for a RSG the exclusion rules would be used in the same manner as they would be used for a single BA. This applies to both multiple contingencies occurring within one minute or less of each other being treated as a single Contingency and to Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period."
Yes
Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.
ISO SRC
No
ERCOT agrees with the SRC comments. However, in addition to the SRC comments, ERCOT offers the following: ERCOT does not agree with additional details in the section that attempts to provide clarification. See the two excerpts below: Quote from Additional Compliance Information section: "To be clear a BA is responsible for the MSSC at all times (the MSSC value at any given time may be more or less than the annually identified prospective MSSC). An undefined "common mode" failure can occur but it is exempted from R4's requirement to meet the BA's or RSG's disturbance recovery criteria within the Disturbance Recovery Period. An undefined common mode failure (i.e. a disturbance that exceeds the MSSC) must be reported to allow the ERO to help ensure that it is not a continuing condition." There should be a period after the word "reported" and the phrase "to allow the ERO to help ensure that it is not a continuing condition." should be struck and removed. Quote from Additional Compliance Information section: "The Reporting only category is designed to track multiple contingency events that are not subject to Requirement R4. This category is designed to ensure that common mode (single point of failures) events are not missed. Thus if two or more contingencies repeatedly occure, the expectation was that the ERO would have the information to alert the BA that the two contingencies must be considered as a singleevent and thus considered as the MSSC." The entire last sentence should be struck and removed. BA's are the functional entities responsible for coordinating with RC's, other BAs, TOPs, and GOPs to determine if a common mode failure requires a different MSSC. The ERO (NERC) is an oversight entity responsible for developing reliability standards and monitoring and enforcing compliance with those standards. It is not a functional entity. As such, it has no role in functional responsibilities, including the establishment of single contingencies and

operating to respect such contingencies in accordance to the applicable NERC standards and requirements. Accordingly, it is inappropriate for the interpretation to suggest, either directly or indirectly, that the ERO is in a position to monitor contingencies on the system, common mode or otherwise, to determine if such reoccurrences warrant consideration of multiple contingencies as a single contingency that could serve as an areas MSCC. There is explicit language in the interpretation that places the ERO in this role. Because this exceeds the scope of the ERO's functions and authority the interpretation must be revised to remove the problematic language. The above revisions are intended to address this issue, and ERCOT respectfully suggests the SDT make the suggested deletions.
Yes
ERCOT agrees with the SRC comments.
Yes
ERCOT agrees with the SRC comments.
Individual
Brett Holland
Kansas City Power & Light
Yes
Yes
Yes

Consideration of Comments

Interpretation of BAL-002-0 R4 and R5 by NWPP Reserve Sharing Group
Project 2009-19

The Project 2009-19 Drafting Team thanks all commenters who submitted comments on the proposed Interpretation of BAL-002-0 (R4, R5, and Section D 1.4) for the Northwest Power Pool Reserve Sharing Group. The interpretation was posted for a 45-day public comment period from July 25, 2012 through September 4, 2012. Stakeholders were asked to provide feedback on the interpretation and associated documents through a special electronic comment form. There were 25 sets of comments, including comments from approximately 96 different people from approximately 56 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

Of those responders that disagreed with the interpretation, the majority questioned the use of the "Additional Compliance Information" in providing an interpretation of the requirements. The IDT explained that the NERC BOT specifically allowed the use of the reference materials in developing this interpretation. The IDT further explained that the NERC BOT recognized that in the conversion of NERC Policies to Version 0 standards, critical information was placed in sections outside of the requirements themselves and that strict construction policy in the case of the DCS standard was not consistent with the standard itself.

A few of the responders questioned how an RSG was to respond and the amount of time allowed to respond. The IDT explained that the clarification requested by NWPP was not about how an RSG was to respond or the amount of time allowed but instead focused on under what conditions could a Disturbance be excluded for compliance evaluation.

Some responders felt that the terms "pre-acknowledged RSGs" and "dynamically allocated RSGs" were not defined and therefore should not be used. The IDT explained that the terms "pre-acknowledged" and "dynamic" were used in the common English terms to be an RSG that is "recognized ahead of time rather than an after-the-fact". And an RSG that is used on an on-call basis and thus its responding members are "not static", respectively.

A few responders questioned why the rules were different for an RSG. The IDT explained that a "pre-acknowledged RSG" knows who is participating and who is not. However, a "dynamically allocated RSG" operates only on an on-call basis and cannot determine who is responsible and who is not until everyone who wants to participate has communicated their desire to participate.

A few responders questioned which version of the BAL-002 (BAL-002-0 or BAL-002-1) this interpretation would apply to. The IDT explained that although the interpretation was requested for BAL-002-0 it would apply to BAL-002-1 as well.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	David Kiguel	Hydro One Networks Inc.	NPCC	1
10.	Michael Lombardi	Northeast Utilities	NPCC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10

11.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
12.	Bruce Metruck	New York Power Authority	NPCC	6
13.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
14.	Robert Pellegrini	The United Illuminating Company	NPCC	1
15.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
16.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
17.	Michael Jones	National Grid	NPCC	1
18.	Brian Robinson	Utility Services	NPCC	8
19.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
20.	Donald Weaver	New Brunswick System Operator	NPCC	2
21.	Michael Schiavone	National Grid	NPCC	1
22.	Wayne Sipperly	New York Power Authority	NPCC	5
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2. Group	Terry Bilke	ISO-RTO Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ben Li	IESO	NPCC	2
2.	Steve Meyers	ERCOT	ERCOT	2
3.	Greg Campoli	NYISO	NPCC	2
4.	Ali Miremadi	CAISO	WECC	2
5.	Charles Yeung	SPP	SPP	2
6.	Kathleen Goodman	NEISO	NPCC	2
7.	Stephanie Monzon	PJM	RFC	2

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Ben Engelby	ACES Power Marketing Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	Pablo Onate	El Paso Electric	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dennis Malone	El Paso Electric	WECC	1
2.	Tracy Van Slyke	El Paso Electric	WECC	3

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
3.	David Hawkins	El Paso Electric	WECC	5
4.	Tony Soto	El Paso Electric	WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Greg Rowland	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy	RFC	1
2.	Lee Schuster	Duke Energy	FRCC	3
3.	Dale Goodwine	Duke Energy	SERC	5
4.	Greg Cecil	Duke Energy	SERC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	David Dockery	Associated Electric Cooperative Inc - JRO00088	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	James	Murphy	WECC	1
2.	Fran	Halpin	WECC	5
3.	Erika	Doot	WECC	3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	C. J. Brown	Southwest Power Pool	SPP	2
2.	Ron Gunderson	Nebraska Public Power District	MRO	1, 3, 5
3.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
4.	Heath Martin	Southwest Power Pool	SPP	2
5.	Terry Oxandale	Southwest Power Pool	SPP	2
6.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5
7.	Katie Shea	Westar Energy	SPP	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

8.	Jason Smith	Southwest Power Pool	SPP	2
9.	Carl Stelly	Southwest Power Pool	SPP	2
10.	Bryan Taggart	Westar Energy	SPP	1, 3, 5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Gerald Beckerle	SERC Operating Committee Standards Review Team	X	X	X		X	X				X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Stuart Goza	TVA	SERC	1, 3, 5, 6
2.	Melinda Montgomery	Entergy	SERC	1, 3, 6
3.	Oliver Burke	Entergy	SERC	1, 3, 6
4.	Wayne Van Liere	LGE-KU	SERC	3
5.	Marie Knox	MISO	SERC	2
6.	Tim Hattaway	PowerSouth	SERC	1, 5
7.	Ronnie Douglas	Electric Energy, Inc	SERC	5
8.	Brad Young	LGE-KU	SERC	3
9.	Steve Corbin	SERC	SERC	NA
10.	Pat Huntley	SERC	SERC	NA
11.	Robert Thomasson	Big Rivers Electric Corp	SERC	1, 3, 5
12.	Ronnie Douglas	Electric Energy	SERC	1, 3, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
11.	Individual	Michael Falvo	Independent Electricity System Operator		X								
12.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
13.	Individual	Thad Ness	American Electric Power			X		X	X				
14.	Individual	Oliver Burke	Entergy Services, Inc.	X		X		X	X				
15.	Individual	John Appel	Public Utility District #1 of Chelan County	X		X		X	X			X	
16.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
17.	Individual	Carter Edge	SERC										X
18.	Individual	linda Horn	Wisconsin Electric Power Company	X		X		X					
19.	Individual	Greg Travis	Idaho Power Co.										

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
20.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	XX				
21.	Individual	Anthony Jablonski	RelliabilityFirst										X
22.	Individual	Maggy Powell	Exelon Corporation	X		X		X	X				
23.	Individual	Brent Ingebrigtson	LG&E and KU Services Company			X							
24.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								
25.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Organization	Supporting Comments of "Entity Name"
Public Utility District #1 of Chelan County	Chelan PUD supports the interpretation of BAL-002-0 on behalf of the NWPP.
Electric Reliability Council of Texas, Inc.	ISO SRC
Wisconsin Electric Power Company	We are supporting the comments of MISO.

1. **Do you agree with Response 1 of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language.**

Summary Consideration: The majority of the responders agreed with the interpretation.

Of those responders that disagreed with the interpretation, the majority questioned the use of the "Additional Compliance Information" in providing an interpretation of the requirements. The IDT explained that the NERC BOT specifically allowed the use of the reference materials in developing this interpretation. The IDT further explained that the NERC BOT recognized that in the conversion of NERC Policies to Version 0 standards, critical information was placed in sections outside of the requirements themselves and that strict construction policy in the case of the DCS standard was not consistent with the standard itself.

A few of the responders questioned how an RSG was to respond and the amount of time allowed to respond. The IDT explained that the clarification requested by NWPP was not about how an RSG was to respond or the amount of time allowed but instead focused on under what conditions could a Disturbance be excluded for compliance evaluation.

A few responders referenced ALR 2-5 and stated that this should be carried forward in the future. The IDT explained that this interpretation request was not a question about ALR 2-5. What NWPP asked was if there were two contingencies at the same time, does the standard relieve them of the responsibility to respond in the given time frame. To paraphrase the IDT response, "if a BA experiences two simultaneous contingencies where total output was greater than the BAs MSSC, the BA must respond but will not be responsible to comply with the strictures of the requirement."

Organization	Yes or No	Question 1 Comment
Associated Electric Cooperative Inc - JRO00088	No	Remove: The final paragraph beginning with "The Performance Standard Reference document initially included..."Rationale: A text-search of BAL-002-0, downloaded from the NERC website, fails to yield any instances of the word "dynamic", meaning that it appears nowhere within the four-corners of the BAL-002-0 Standard. Responsible Entities are subject only to the Standard's requirements as written and within its Effective Dates 4/1/2005 to 8/5/2010, when BAL-002-1 effectively replaced it. NERC's BOT Approved August 2, 2006 filing with The Commission appears to contain the

Organization	Yes or No	Question 1 Comment
		oldest copy of FERC approved NERC Glossary of Terms Used in Reliability Standards. It contains no instances of the word "dynamic" that correspond in any way to Reserve Sharing Group membership, although "Reserve Sharing Group" and "Reportable Disturbance" are defined within that document. Although the SDT asserts the augmented concept of RSG dynamic membership, those references within this interpretation should be stricken because the "dynamic membership" concept clearly does not exist within the "four-corners of the Standard" which was balloted and approved by industry stakeholders. Instead BAL-002-0 wording indicates that each RSG can establish its own guidance, necessary to comply with the Requirements. Requirement R2 provides each Reserve Sharing Group the flexibility concerning its policies governing how it collectively fulfills its responsibility to meet Requirements R3, R4, R5 and R6. However Requirement R5's parenthetical does appear to provide some governance concerning a BA's reporting within a Reserve Sharing Group when they do not call for reserve activation from its other members, that they are subject to individually reporting their performance in responding to that event. (In either case of reporting per R5 parenthetical, the RSG's collectively-committed units' spinning-mass and short-term governor response would have fulfilled the reliability objective of this Standard, unless the Reportable Disturbance's magnitude was much greater than anticipated by the RSG in its entirety.)

Response: Under normal circumstances Associated Electric Cooperative Inc would be correct that only the stated requirements within the four corners of a standard can be referenced in an interpretation. In this case however, the NERC Board of Trustees specifically allowed the Interpretation Drafting Team to make use of reference materials that were created for the original NERC Policy but that in the conversion from NERC Policy to Version 0 standards those materials were placed in sections outside of the requirements themselves. The BOT recognized that strict constructionism in the case of the DCS standard was not consistent with the standard itself and those who drafted the standard.

Organization	Yes or No	Question 1 Comment
Response 1 deals with the issue of excluding a Disturbance that exceeds the most severe single Contingency of a BA or an RSG. Response 1 does not deal with governance. A group of BAs can form an RSG (please note that despite the fact that RSG is a defined term, it does not mean that all RSGs are the same) and decide how to allocate and measure the service it will provide. However, as the cited reference (Performance Standards Guidelines) states (chapter 6, Reporting) "Where RSGs exist, the Regional Reliability Council is to decide either to report these on a BA basis or on an RSG basis." Thus it is clearly not up to the RSG to make that decision about reporting. If the reporting were left to the RSGs then the standard would be a fill-in-the-blanks standard. The RSG would be allowed after-the-fact to decide whether or not two independent losses would be counted as a reason for not reporting. Such an approach would place the system at risk – and the original drafters of that BAL-002 recognized the need to make clear that to take advantage of this benefit, the dynamic RSG (not all RSGs just those that BAs make use of on an as needed basis) must have permission from their Region to address such events on a composite basis. The question raised by NWPP was not about allowing RSGs to respond, the question was about which conditions would exclude a disturbance that exceeded the MSSC of the BA or RSG. It is clear that for a BA any set of non-common mode contingencies that exceed its MSSC would be excluded. For an RSG that has a variable participation, that situation is by definition unclear. Since BA(1) may lose a resource equal to its MSSC and not call for reserve sharing and fail to comply with the standard, however, unknown to BA(1) is the fact that BA(2) also lost a resource at the same time. BA (2) also did not call for reserve sharing and failed to comply. However, after the fact the RSG observes the situation that as a group they would be permitted to exclude the "composite disturbance". The original drafters recognized that fact and precluded that situation by requiring that the Regions decide which MSSC to accept for a BA and which RSGs are permitted to treat themselves as a single BA. The standard was written to serve reliability and not as a means to avoid responding to disturbances. The BOT recognized that fact and allowed the IDT to respond to the NWPP question on the basis of what the drafters meant as indicated by all available reference material and not be limited by the 4 wall of the requirements.		
American Electric Power	No	We do not understand the interpretation provided by the drafting team based on the requirements of BAL-002-0. As a result, we cannot endorse the interpretation provided.

Organization	Yes or No	Question 1 Comment
Response: The interpretation was not based entirely on the requirements of BAL-002-0, but also on the **Additional Compliance Information** section and other reference material (See response to AECI's question 1 comment) as allowed by the BOT.		
SERC	No	The interpretations process is not an appropriate mechanism to address a compliance monitoring and enforcement issue. Further, the words in the requirements do not support the interpretation, no matter how much the interpretation reflects how the industry and ERO have historically approached the Disturbance Control Standard. The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Specifically, Requirement 1 requires each Balancing Authority to have access to and/or operate Contingency Reserve to respond to Disturbances. Prior to penalties and sanctions under Section 215, the consequence of failing DCS was to require an increase in contingency reserves. This is the "compliance evaluation" referred to under Section D. The expectation is that Balancing Areas respond to the loss of resources regardless of magnitude to restore ACE and minimize the risk to reliable operation of being "out of balance". There was recognition, however, that interconnected operations increased the reliability of the grid by reducing the consequences of a single area being out of balance at any given time and thus allowed the collective greater utilization of installed capacity to serve load rather than retain it as contingency reserves. Thus, the concept of "most severe single contingency" (MSSC) as a criterion against which to require additional contingency reserve was employed and for large contingencies may require more time to respond. Fifteen minutes is a "benchmark" time-frame that is reasonable to expect a Balancing Area to recover from a credible contingency. There is nothing magical about that time (it used to be 10 minutes), but the BA should not "lean" on the system longer than is

Organization	Yes or No	Question 1 Comment
		necessary regardless of the magnitude. Performance outside this benchmark can only be determined by an inspection of the facts and circumstances of each instance. All Balancing Authorities and Reserve Sharing Groups are required to review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies. The NERC glossary defines Contingency as the “unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element”. Thus, the compliance action or inaction ("decline to pursue") with respect to the performance of an entity against the stated requirements in the standard is a matter of the CMEP and should not be addressed through the standards interpretations process. Compliance activity should be based on the facts and circumstances of each case measured against the performance requirements of the standard. Standards (including interpretations) are for describing the behaviors and actions of registered entities necessary for the reliable planning and operation of the bulk power system not the Compliance Enforcement Authority. Informed and expert discretion rather than this interpretation (which requires inaction) is a better answer for the Reliability Assurer. Further, ALR 2-5 has a stated purpose as a measure of how much risk a system is exposed to for extreme or unusual contingencies (Simultaneous Contingencies - Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation). The results of ALR 2-5 are expected to help validate current contingency reserve requirements and document how often these “extreme or unusual” contingencies occur. These activities should

Organization	Yes or No	Question 1 Comment
		continue.

Response: The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance.

Prior to penalties and sanctions under Section 215, the consequence of failing DCS was to require an increase in contingency reserves. This is the "compliance evaluation" referred to under Section D.

Thus, the concept of "most severe single contingency" (MSSC) as a criterion against which to require additional contingency reserve was employed and for large contingencies may require more time to respond.

This is not correct. MSSC was used to recognize the fact that the Reserve obligation was to include not simply the largest "generator" but that the largest common mode failure must also be covered. That included single interchange schedules that could be curtailed instantaneously. However, MSSC varies as a function of the assets operating at any given time. Thus the MSSC may be 1500 when a BA's 1500 MW nuclear unit is running, but then becomes 500 when that nuclear unit is off, and the BAs next largest unit is a 500 MW generator.

The time response was not addressed in the NWPP question or in the interpretation. The question NWPP asked was what is excluded from compliance penalty by the DCS standard. It is clear that the standard held BAs to meet the DCS requirement when they had a contingency. It is also clear that contingencies less than 80% of the MSSC were not mandated to be "reported". The drafters of the standard did not intend that contingencies below 80% did not require action, but the consequence of the non-reporting exception provided that situation.

ALR 2.5 is not in question. What NWPP asked was if there are two contingencies at the same time, does the standard relieve them of the responsibility to respond in the given time frame. To paraphrase the IDT response, "if a BA experiences two simultaneous contingencies who total output was greater than the BAs MSSC, the BA must respond but will not be responsible to comply with the strictures of the requirement."

SERC's contention regarding the Reliability Assurer may or may not be true, but the IDT is tasked with interpreting what the standard

Organization	Yes or No	Question 1 Comment
in question says. SERC is welcome to submit a SAR to change the standard.		
ReliabilityFirst	No	ReliabilityFirst votes in the Negative for the Interpretation of BAL-002 since ReliabilityFirst believes the drafted interpretation to Question 1 incorrectly expands on the language in Requirement R4 and incorrectly attempts to explain how to comply with the Requirement. If a reportable disturbance occurs (i.e. contingencies that are greater than or equal to 80% of the most severe single Contingency) and is greater than the most severe single Contingency, ReliabilityFirst questions why an entity would not be required to meet the Disturbance Recovery Criterion. Nowhere within the requirements are there exceptions for Reportable Disturbance greater than the most severe single Contingency. Based on R4, the applicable entity "...shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances". For example, if an entity failed to meet the meet the Disturbance Recovery Criterion for a disturbance equaling 110% of their most severe single Contingency, they would potentially be found non-compliant. In addition, ReliabilityFirst does not believe the quasi definition of "Simultaneous Contingencies" within the "Additional Compliance Information" is not enforceable since it is not a Reliability Requirement, and is not even a NERC Defined term.
Response: Regarding RFC's concern about expanding the language of the requirement, the IDT refers them to the IDT's response to AEC Inc. An IDT is not formed to respond to why a standard mandates what it mandated; the IDT is only obligated to interpret what the drafters meant by the mandated requirement.		

Organization	Yes or No	Question 1 Comment
Regarding Excludable Disturbances RFC is correct that exclusions are not in the requirement, but as explained in the AEC Inc response the IDT was permitted to use other reference material. RFC is referred to the cited reference (Performance Standards Reference Guidelines - http://www.nerc.com/docs/oc/rs/Item_4e-PSRD_revised_112607.pdf) Reporting Section items a.2. And a.3. That specifically references Excludable Disturbances. According to the requirement and the associated reference materials the IDT concludes that a BA cannot be held non-compliant with a disturbance that is 110% of their MSSC. The standard specially excludes such disturbances from compliance. Regarding Simultaneous Contingencies, the IDT would simply refer to the BOT allowance for the IDT to include such reference material.		
LG&E and KU Services Company	No	The IDT's explanation of MSSC may be uneccessary and confusing, especially statements such as: "MSSC is a variable that the BA knows and operates to in real time."''Thus the BA knows its MSSC which can vary from hour to hour and minute to minute."''To be clear a BA is responsible for the MSSC at all times (the MSSC value at any given time may be more or less than the annually identified prospective MSSC)."In the absence of an identifiable/specific reason, which is recognized by the BA in advance, the real-time MSSC should not exceed the prospective MSSC. Unless such an abnormal situation exists, all evaluations of DCS compliance must be based on the prospective MSSC value. The IDT needs to be very clear with any language suggesting that the real-time MSSC can exceed the planned/recognized/"prospective" MSSC. If a disturbance exceeds the planned/recognized/"prospective" MSSC value, it is outside the definition of MSSC and should not be subject to compliance evaluation. The requirement for a prospective MSSC is for the MSSC be used for planning purposes, not for real-time operations, even though it is

Organization	Yes or No	Question 1 Comment
		used in such operations. MSSC is not a defined term in the NERC Glossary but work is in progress under NERC Project 2010-14.1 to develop a definition of MSSC. Therefore, it would not be in the best interest of the IDT in providing this interpretation to attempt to describe or define MSSC. LGE and KU Services recommends all language related to the IDT's explanation of MSSC be deleted from Response 1. Also, the language explaining the "Compliance and reporting category" and "Reporting only category" appears to be outside the inquiry of Question 1 and is suggested for deletion.LGE and KU Services suggests Response 1 be reduced to simply the first sentence of the response as it clearly answers Question 1: "The IDT agrees that the Disturbance would be excluded from compliance."
Response: Thank you, the IDT agrees that it is necessary to be "very clear", hence the explanation. To use the proposed straight forward answer would leave others asking what is meant. Since your answer and our answer agree, the IDT will retain the explanation.		
Electric Reliability Council of Texas, Inc.	No	ERCOT agrees with the SRC comments. However, in addition to the SRC comments, ERCOT offers the following: ERCOT does not agree with additional details in the section that attempts to provide clarification. See the two excerpts below: Quote from Additional Compliance Information section: "To be clear a BA is responsible for the MSSC at all times (the MSSC value at any given time may be more or less than the annually identified prospective MSSC). An undefined "common mode" failure can occur but it is exempted from R4's requirement to meet the BA's or RSG's disturbance recovery criteria within the Disturbance Recovery Period. An undefined common mode failure (i.e. a disturbance that exceeds the MSSC) must be reported to allow the ERO to help ensure that it is not a continuing condition."There should be a period after the word "reported" and the phrase "to allow the ERO to help ensure

Organization	Yes or No	Question 1 Comment
		that it is not a continuing condition." should be struck and removed. Quote from Additional Compliance Information section: "The Reporting only category is designed to track multiple contingency events that are not subject to Requirement R4. This category is designed to ensure that common mode (single point of failures) events are not missed. Thus if two or more contingencies repeatedly occur, the expectation was that the ERO would have the information to alert the BA that the two contingencies must be considered as a single event and thus considered as the MSSC."The entire last sentence should be struck and removed. BA's are the functional entities responsible for coordinating with RC's, other BAs, TOPs, and GOPs to determine if a common mode failure requires a different MSSC. The ERO (NERC) is an oversight entity responsible for developing reliability standards and monitoring and enforcing compliance with those standards. It is not a functional entity. As such, it has no role in functional responsibilities, including the establishment of single contingencies and operating to respect such contingencies in accordance to the applicable NERC standards and requirements. Accordingly, it is inappropriate for the interpretation to suggest, either directly or indirectly, that the ERO is in a position to monitor contingencies on the system, common mode or otherwise, to determine if such reoccurrences warrant consideration of multiple contingencies as a single contingency that could serve as an areas MSCC. There is explicit language in the interpretation that places the ERO in this role. Because this exceeds the scope of the ERO's functions and authority the interpretation must be revised to remove the problematic language. The above revisions are intended to address this issue, and ERCOT respectfully suggests the SDT make the suggested deletions.
Response: The IDT is responsible to interpret what the requirement meant. The idea of having a requirement for reporting excludable disturbances just for the sake of reporting does not make sense. The reason for reporting was to ensure that reliability entities do not take advantage of the exclusion. At the time the standard was written the NERC Performance Subcommittee		

Organization	Yes or No	Question 1 Comment
(translated here to be the ERO) was to collect and evaluate those instances.		
ISO-RTO Standards Review Committee	Yes	We agree with the response. However, we do not agree with some of the details in the section that attempts to provide clarification, excerpt below:"Most Severe Single Contingency (MSSC) - this can be the loss of the BA's or RSG's single largest operating generator, or it can be a known common mode failure that causes more than one generator to fail when the contingency occurs; or it can be a firm transaction."We do not agree the term "firm transaction". The loss of or interruption to a transaction, regardless of its firmness, represents a loss of resource which may trigger the need to comply with the DCS requirement. In other words, a temporary deficiency in a BA's resource has no distinction on whether it is caused by the loss/interruption to a firm transaction or a non-firm transaction. Further, the term "firm transaction" is subject to debate as to whether the firmness is in the energy component or in the transmission service component. If the proposed clarification is to be adopted by registered entities as a guideline for compliance (which this interpretation appears to be attempting to provide), then it can have a potential for opening up a reliability gap since a BA or an RSG may not respond to a resource contingency resulting from the loss or an interruption to a non-firm transaction (however the firmness is interpreted to be). We suggest to remove the word "firm" from the clarification section.
Response: Thank you for your affirmative response and clarifying comment.		
ACES Power Marketing Standards Collaborators	Yes	We conceptually agree with the position of the interpretation. However, we believe that the current response expands issues that were not raised in the original question. One example is that the "MSSC value at any given time may be more or less than the annually identified prospective MSSC" is

Organization	Yes or No	Question 1 Comment
		contradictory to the interpretation. How could the MSSC value could ever be higher than the list of candidate MSSCs identified in the annual review. Also, in the “reporting only” category in response 1, the IDT incorrectly characterizes that the ERO would have authority or the information to alert the BA that two (or more) contingencies must be considered as a single event and thus considered as the MSSC. The ERO does not determine the MSSC, the BA or RSG makes that determination. For simplicity and clarity, we recommend that the interpretation state: Disturbances greater than MSSC are excluded from the compliance calculation, based on the additional compliance information section of BAL-002-0. The IDT could strike everything following this statement from the interpretation and would convey the same message in a more clear and concise manner.
Response: Thank you for your affirmative response and clarifying comment. An MSSC can be higher if the BA expanded its boundaries, or if the BA made an interchange schedule larger than expected.		
El Paso Electric	Yes	El Paso Electric (EPE) generally supports the first interpretation proposed by the IDT but is concerned with the language immediately following "To be clear..." because it does not acknowledge the fact that many BAs have placed responsibility in the hands of a RSG. The interpretation states that "...a BA is responsible for the MSSC at all times...". EPE believes that this responsibility should be shared with a RSG, where appropriate. EPE would be more comfortable with an interpretation that read "To be clear a BA or RSG, as applicable, is responsible for the MSSC at all times..."
Response: The issue in question depends on the type of RSG involved. The BA is responsible. However, if a BA makes use of an RSG then based on the rules of the RSG it could be the BA, it could be the RSG or it could be some combination. The IDT believes that its response properly allows for any of the above. Based on the governance of the RSG and the Region it is in.		
Duke Energy	Yes	We suggest that there should be a SAR to define the terms MSSC and

Organization	Yes or No	Question 1 Comment
		"excludable disturbance" add them to the NERC Glossary.
Response: Thank you for your affirmative response and clarifying comment. There –presently is a project under development to address the issue you have brought forward (Project 2010-14.1 BARC – Reserves).		
SPP Standards Review Group	Yes	This interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		
SERC Operating Committee Standards Review Team	Yes	The SERC OC Standards Review Group gladly presents the following comments. The SERC OC Standards Review Group agrees only with the interpretation portion of the response. The Group strongly disagrees there is a need for the additional explanation of the interpretation. The explanation presents more confusion and questions around the Standard. The simple interpretation is very clear and concise.
Response: Thank you for your affirmative response and clarifying comment.		
Independent Electricity System Operator	Yes	We agree with the response. However, we do not agree with some of the details in the section that attempts to provide clarification, excerpt below:"Most Severe Single Contingency (MSSC) - this can be the loss of the BA's or RSG's single largest operating generator, or it can be a known common mode failure that causes more than one generator to fail when the contingency occurs; or it can be a firm transaction."We do not agree the term "firm transaction". The loss of or interruption to a transaction, regardless of its firmness, represents a loss of resource which may trigger the need to comply with the DCS requirement. In other words, a temporary deficiency in a BA's resource has no distinction on whether it is caused by the loss/interruption to a firm transaction or a non-firm transaction.

Organization	Yes or No	Question 1 Comment
		Further, the term “firm transaction” is subject to debate as to whether the firmness is in the energy component or in the transmission service component.If the proposed clarification is to be adopted by registered entities as a guideline for compliance (which this interpretation appears to be attempting to provide), then it can have a potential for opening up a reliability gap since a BA or an RSG may not respond to a resource contingency resulting from the loss or an interruption to a non-firm transaction (however the firmness is interpreted to be). We suggest to remove the word “firm” from the clarification section.
Response: Thank you for your affirmative response and clarifying comment. See our response to SRC.		
Nebraska Public Power District	Yes	The interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		
Idaho Power Co.	Yes	
South Carolina Electric and Gas	Yes	
Exelon Corporation	Yes	
Kansas City Power & Light	Yes	
Northeast Power Coordinating Council	Yes	
Bonneville Power Administration	Yes	
Arizona Public Service Company	Yes	

Organization	Yes or No	Question 1 Comment
Manitoba Hydro	Yes	
Entergy Services, Inc.	Yes	

2. Do you agree with Response 2 of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language.

Summary Consideration: The majority of the responders agreed with the interpretation.

Of those responders that disagreed with the interpretation the majority felt that the terms "pre-acknowledged RSGs" and "dynamically allocated RSGs" were not defined and therefore should not be used. The IDT explained that the terms "pre-acknowledged" and "dynamic" were used in the common English terms to be an RSG that is "recognized ahead of time rather than an after-the-fact". And an RSG that is used on an on-call basis and thus its responding members are "not static", respectively.

A few responders questioned why the rules were different. The IDT explained that a "pre-acknowledged RSG" knows who is participating and who is not. However, a "dynamically allocated RSG" operates only on an on-call basis and cannot determine who is responsible and who is not until everyone who wants to participate has communicated their desire to participate.

Organization	Yes or No	Question 2 Comment
Duke Energy	No	It's not clear what the drafting team is saying, particularly the reference to "dynamic allocation of membership". What's the difference between pre-acknowledged RSGs and dynamically allocated RSGs, and why are the exclusion rules different?
Response: RSG as it pertains to structure is not a common entity. Some RSG are designed to be "on-call" and hence have a dynamic membership. The aforementioned RSG could consist of a pool of 20 BAs, but have 2 (of 20) members who are responding for one disturbance and 15 (of 20) for the next. While the pool of BAs may be fixed, based on the governance of the particular RSG, the obligations of the RSG are allocated only to those who agree to participate for the given disturbance. Of course other RSGs may operate as a unit for all disturbances that occur and thus all pool members are obligated for all disturbances (in effect they become a single BA for purposed of DCS).		

Organization	Yes or No	Question 2 Comment
The exclusion is really the same, what is different is in deciding who is to be counted in multiple disturbances (note this difference is small since the probability of one BA in an RSG having a disturbance at the same as another BA having an independent disturbance is low). But the fact remains that weather conditions could and do span multiple BAs and can result in such simultaneous disturbances (although it is more likely that one BA would be more likely to experience such independent disturbances.) For a pre-acknowledge RSG, one knows exactly who is participating and who is not. In an RSG that operates only on an on-call basis (i.e. a dynamically-allocated RSG) one cannot determine who is responsible and who is not UNTIL everyone who wants to participate has communicated their participation.)		
SERC Operating Committee Standards Review Team	No	The SERC OC Standards Review Group feels the interpretation and clarification are both very confusing, thus raising numerous other questions. The use of the words “pre-acknowledged RSGS” and “dynamic allocated RSGS” appear to be new terms introduced in the response. Also, a reference to a Technical Document is made in the response. The Group is unsure of what Technical Document the IDT is referring. Nor does the Group understand if such reference to the Technical Document is an agreement with such document by the IDT or if the Technical Document is referenced as to be included in the response and subject to being opened and the processes and procedures of such document being made part of a compliance audit.
Response: The Technical document can be found at the following link. **http://www.nerc.com/docs/oc/rs/Item_4e-PSRD_revised_112607.pdf** The BOT recognized that the creation of DCS was supported by other materials such as Reference Documents and a Frequently Asked Questions. These documents hold the key to what was meant by the DCS requirements and are important in any interpretation.		
American Electric Power	No	We do not understand the interpretation provided by the drafting team based on the requirements of BAL-002-0. As a result, we cannot endorse the interpretation provided. For example, it is not clear to us exactly what “pre-acknowledged” or “dynamic” means in regards to Reserve Sharing Groups. These terms are not found anywhere within the standard itself, nor are they commonly used to describe or qualify Reserve Sharing Groups.

Organization	Yes or No	Question 2 Comment
Response: The terms "pre-acknowledged" and "dynamic" are used in the common English terms to be an RSG that is "recognized ahead of time rather than after-the-fact", and an RSG that is used on an on-call basis and thus its responding members are "not static", respectively.		
SERC	No	See answer to question #1.
Response: See response to Question #1		
LG&E and KU Services Company	No	The meaning and use of the adjectives "pre-acknowledged" and "dynamically allocated" in description of RSG in Response 2 seem to be uneccessary, confusing and beyond the scope of Question 2. As stated in Response 2, there is a NERC Glossary definition of RSG and that is the subject of Question 2 - not the applicability of R5 to organizational variations of RSGs. The IDT has referenced a "Technical Document" that has not been included in the posting. The content therefore of the Technical Document is unknown. LGE and KU Services suggests Response 2 be reduced to only the language used in the "In summary,...." portion of the response as it clearly answers Question 2, edited as follows:"The Standard was written to provide RSGs the same considerations as a single BA for purposes of exclusions from DCS compliance evaluation. Thus for a RSG the exclusion rules would be used in the same manner as they would be used for a single BA. This applies to both multiple contingencies occurring within one minute or less of each other being treated as a single Contingency and to Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period."
Response: Question 2 is about exclusions for RSGs. The reference material (http://www.nerc.com/docs/oc/rs/Item_4e-PSRD_revised_112607.pdf) makes the distinction about whether or not the Region agrees ahead of time (pre-acknowledged) or whether or not there is an known MSSC for the RSG (if the responders are dynamically joining or not). Thank-you for your suggestion, but given the responses to the interpretation, the IDT will retain the explanation.		

Organization	Yes or No	Question 2 Comment
ACES Power Marketing Standards Collaborators	Yes	We largely agree with the interpretation. However, we want to point out that the concept of pre-acknowledged RSGs have disincentivized Adjacent Balancing Authorities (not in a pre-acknowledged RSG) to provide reserves in less than 10 minutes even if they are capable. If an Adjacent Balancing Authority provides emeregency energy in an amount that exceeds its own MSSC with a ramp less than 10 minutes and fails to recover its ACE from within 15 minute of the initial disturbance, the Adjacent BA may be found non-compliant despite the fact the it provided the appropriate reliability assistance. Compliance should not disincentivize actions that ensure reliability.
Response: The IDT agrees that the terms of an agreement may influence a BA on agreeing to participate in a given type of RSG. But the responsibility and allocation of penalties is a governance matter defined with the dictates of the agreement the BA signs, it is not a matter for the requirement. This interpretation neither incents of dis-incents making an agreement of any kind. If an entity does not agree with the rules of a proposed RSG agreement they are not obligated by this interpretation to sign that agreement.		
El Paso Electric	Yes	EPE generally supports the second interpretation by the IDT but requests that IDT clarify the scope of compliance evaluations for BAs who are part of a RSG and experienced a reportable event, without regard to whether any individual BA member of the RSG requested assistance. If a RSG determines that the group as a whole complied with CPS then there should be no need for any individual BA review or reporting under R5, without regard to whether the BA called for reserve activation from other RSG members, or not. The interpretation should include this clarification.
Response: This interpretation is based on the concept that BAs would submit "Reportable Disturbances". These reports provide more than compliance information, they provide information on the state of responses. This information was deemed valuable to the Resources Subcommittee. Even in today's environment there is a need to "self-report" non-compliance. The question raised by the NWPP is for a situation in which a BA is non-compliant with the DCS requirement but because of circumstances (explained in the Reference documents and in the Interpretation), the BA is excused from complying with the requirement (i.e. the disturbance is excludable). The decision for		

Organization	Yes or No	Question 2 Comment
exclusion should be easy but as indicated by some responses there are CEAs who say they would hold entities non-compliant for such events.		
SPP Standards Review Group	Yes	Again, this interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		
Nebraska Public Power District	Yes	The interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		
Electric Reliability Council of Texas, Inc.	Yes	ERCOT agrees with the SRC comments.
Response: Thank you for your affirmative response and clarifying comment.		
Associated Electric Cooperative Inc - JRO00088	Yes	Rationale: In our opinion, the IDT failed to answer Question #2, which could have been answered with a simple "Yes". Instead, they appear to attempt legislating upon particulars of how all RSGs should structure portions of their policies under R2, by again referring to the concept of "dynamic membership". Our understanding is that such expansion of Standard governance can only be done under SDT effort and subsequent industry approval through the ballot process. (See AECI's earlier response to Question 1 above.)
Response: Thank you for your affirmative response and clarifying comment.		
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 2 Comment
Arizona Public Service Company	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
Entergy Services, Inc.	Yes	
Idaho Power Co.	Yes	
South Carolina Electric and Gas	Yes	
RelliabilityFirst	Yes	
Exelon Corporation	Yes	
Kansas City Power & Light	Yes	
Northeast Power Coordinating Council	Yes	
ISO-RTO Standards Review Committee	Yes	

3. **Do you agree with Response 3 of this interpretation? If not, what, specifically, do you disagree with? Please provide specific suggestions or proposals for any alternative language.**

Summary Consideration: The majority of the responders agreed with the interpretation.

Of those responders that disagreed with the interpretation the majority questioned which version of the BAL-002 (BAL-002-0 or BAL-002-1) this interpretation would apply to. The IDT explained that although the interpretation was requested for BAL-002-0 it would apply to BAL-002-1 as well.

A few responders objected to the wordiness of the response. The IDT explained that their intent was to encourage an understanding of the interpretation. The first two paragraphs were basically a restatement of the requirement and the last paragraph was the actual interpretation.

Organization	Yes or No	Question 3 Comment
Duke Energy	No	It's not clear what the drafting team is saying. Does "excluded from compliance evaluation" mean that R4 does not apply to Disturbances that exceed the MSSC for a BA or RSG? Does it matter if the RSG is pre-acknowledged or dynamically allocated? The drafting team's response to Question 2 seems to indicate that it does matter. We agree that DCS is not applicable for losses greater than the MSSC, and also that DCS compliance is not required for losses less than 80% of the MSSC (or lower if a lower threshold is adopted for DCS reporting). This interpretation is performed on BAL-002-0, but the current effective standard is BAL-002-1 as of 4-1-2012. If the interpretation is approved, what is its applicability to BAL-002-1? Under BAL-002-0 the default Disturbance Recovery Period could be adjusted to better suit the needs of an Interconnection (R4.2) and the default Contingency Reserve Restoration Period could be adjusted to better suit the reliability targets of the Interconnection (R6.2), both based on analysis approved by the NERC Operating Committee. This has been deleted from both requirements in BAL-002-1.

Organization	Yes or No	Question 3 Comment
Response: The IDT believes the interpretation is clear and that the Interpretation would apply to the current version as well as to the former version.		
American Electric Power	No	We do not understand the interpretation provided by the drafting team based on the requirements of BAL-002-0. As a result, we cannot endorse the interpretation provided.
Response: See response to Question #1.		
SERC	No	See Response to question #1.
Response: See response to Question #1		
Exelon Corporation	No	Response 3 of the interpretation that requests clarification on the phrase “excluded from compliance evaluation” could be clearer. The first portion of the response gives the impression that the IDT is of the opinion that the obligation to comply with the DCS extends to events larger in magnitude than the MSSC. The paragraphs that follow go on to clarify that an event greater than the MSSC would not be required to recover ACE within 15 minutes, making compliance with the DCS not mandated in these instances. The latter (disturbances exceeding the MSSC being excluded from DCS compliance and 15 minute recovery) is consistent with practice and in line with the interpretation indicated by the NWPP. In order to more fully clarify the interpretation, the IDT should make clear that compliance with the DCS is not mandated for disturbances exceeding the MSSC.
Response: The first two paragraphs are meant as a restatement of the requirements. The last paragraph is the interpretation.		
ISO-RTO Standards Review Committee	Yes	It might be clearer if the reponse added the phrase [of the Disturbance Control Standard] after “loss shall be reported, but excluded from compliance evaluation”.

Organization	Yes or No	Question 3 Comment
		Following a large event, the BA would still be accountable for other standards (e.g. IRO standards)
Response: Thank you for your affirmative response and clarifying comment.		
ACES Power Marketing Standards Collaborators	Yes	We agree for the most part with this interpretation. However, we do have a few points we would like to address. We recommend striking the entire second paragraph because it is irrelevant. The standard does not say comply with DCS "for every reportable disturbance." The key is whether a BA is required to recover ACE within 15 minutes for contingencies greater than MSSC, and that answer is no. The IDT should keep the interpretation simple. A recommendation for wording the interpretation: A BA is not required to recover ACE within 15 minutes for contingencies greater than MSSC, as stated in section 1.4 ("Additional Compliance Information").We recommend that the IDT reduce the amount detail in the rationale and focus on the three questions in the request. The current draft of the interpretation is wordy, confusing and provides excessive details instead of answering the questions that were asked. Also, the IDT did not state that this interpretation would apply to BAL-002-1, which has been enforceable since 4/1/2012. If NERC is going to continue with the interpretation process for BAL-002, the interpretation should apply to both versions of the standard. Finally, we encourage NERC to consolidate standard projects. There are currently 10 standard projects under development for BAL standards. NERC should consider either a consolidation to a reduced amount of BAL projects or even a single project to cover all BAL issues in order to avoid duplication, overlap, inefficient use of resources and confusion.
Response: Thank you for your affirmative response and clarifying comment. The wordy explanation was meant to encourage an understanding of the interpretation. Given the overwhelming support that approach seems to have been effective.		

Organization	Yes or No	Question 3 Comment
The Interpretation would apply to the current version as well as to the former version. This is an interpretation not a standard development. There is a need to respond to this issue as soon as possible. The BAL project may or may not receive approval and to link that Project with this Interpretation would not be helpful to those waiting for this interpretation.		
Associated Electric Cooperative Inc - JRO00088	Yes	We agree with this summary determination. In addition, the August 2, 2006 NERC BOT approved, and subsequently FERC accepted Glossary definition for Reportable Disturbance clearly specified that the definition "not be retroactively adjusted in response to observed performance", adding weight to this drafting-team's response to Question 3. (FERC_Filing_Proposed_Reliability_Standards_Docket_RM06-16-000.pdf)
Response: Thank you for your affirmative response and clarifying comment.		
SPP Standards Review Group	Yes	Again, this interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		
Independent Electricity System Operator	Yes	(1) We generally agree with the proposed interpretation. However, we are not sure if this request fits well into NERC's criteria for acceptance as a valid request since it appears that the requester asks specifically on the compliance implications and compliance elements. We suggest the interpretation drafting team (IDT) to evaluate whether or not the request is a valid one that seeks clarity on the requirements, rather than on the compliance aspects of the standard/requirements. If the IDT does assess that the questions are addressing a compliance issue, then we suggest the IDT to bring this to the attention of the Standards Committee for a determination of the appropriate means to address the questions.

Organization	Yes or No	Question 3 Comment
		(2) The IESO agrees with NERC's interpretation of BAL-002. However, we believe additional discussion and thought need to be applied to other Standards to ensure that no gaps or overlaps exist in both task execution and Standard application. Different Standards obligate Reliability Entities to fulfill certain tasks as it pertains to balancing: conditions. This includes: o BAL- 002 outlines obligations to balance following Reportable Disturbances; o EOP-002 outlines obligations to balance during Capacity and Energy Emergencies; and o TOP-001 outlines obligations to balance during System Emergencies. All of these Standards have similarities but need interpretation to ensure consistent application. These interpretations are based on an understanding of the NERC Functional Model and upon clear statements in the purpose and requirement sections in the Standards. We believe that the objective of each of the Standards list above must be clarified to reduce confusion and support consistent application.
Response: Thank you for your affirmative response and clarifying comment. The IDT is not making a decision on a given compliance issue, it is simply providing an interpretation of what is meant by excludable disturbances. It is not within the purview of an IDT to address other issues outside the bounds of the proposed question. The IESO is encouraged to participate in Projects that address the above requirements or to submit a SAR to rectify their issues and concerns.		
Nebraska Public Power District	Yes	The interpretation is consistent with the common understanding of the industry on how BAL-002-0 has been historically applied. We thank the IDT for the clarification.
Response: Thank you for your affirmative response and clarifying comment.		

Organization	Yes or No	Question 3 Comment
Electric Reliability Council of Texas, Inc.	Yes	ERCOT agrees with the SRC comments.
Response: Thank you for your affirmative response and clarifying comment.		
SERC Operating Committee Standards Review Team	Yes	NONE
El Paso Electric	Yes	No Comment.
Bonneville Power Administration	Yes	BPA is in support of BAL-002-0 Interpretation and has no comments or concerns at this time.
Idaho Power Co.	Yes	
South Carolina Electric and Gas	Yes	
LG&E and KU Services Company	Yes	
Kansas City Power & Light	Yes	
Northeast Power Coordinating Council	Yes	
Arizona Public Service Company	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 3 Comment
Entergy Services, Inc.	Yes	
ReliabilityFirst		ReliabilityFirst disagrees with the drafted interpretation. Regardless of the references to outside sources (the reserve requirement specified in R3.1 of BAL-002-0, the text of Section 1.4 of Part D of BAL-002-0, and the documented history of the development of BAL-002-0), compliance is to be assessed on a requirement by requirement basis. Requirement R4 requires that an applicable entity "...shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances". Clearly, there is no exception listed within the requirements for Reportable Disturbances greater that the most severe single Contingency.
Response: The IDT disagrees with your perception. In addition, the industry ballot indicates that the Industry does not agree with RFC's perception.		

END OF REPORT

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard
Date submitted: September 2, 2009
Date accepted: September 2, 2009
Contact information for person requesting the interpretation:
Name: Northwest Power Pool Reserve Sharing Group, in care of Jerry Rust, Agent
Organization: Northwest Power Pool Reserve Sharing Group
Telephone: 503-445-1074
E-mail: jerry.rust@nwpp.org
Identify the standard that needs clarification:
Standard Number (include version number): BAL-002-0
Standard Title: Disturbance Control Performance
Identify specifically what requirement needs clarification:

Requirement Number and Text of Requirement:

B. Requirements

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R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.

R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.

***

R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. *** Compliance may be demonstrated by either

of the following two methods:

R.5.1 The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R.5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

***

D. **Compliance**

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1.4 Additional Compliance Information

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Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

<u>Clarification needed</u>:

The Northwest Power Pool Reserve Sharing Group respectfully requests clarification as to whether:

(1) although a Disturbance[1] that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), the Disturbance is excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group;

(2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve

[1] Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and

(3) the meaning of the phrase "excluded from compliance evaluation" as used in Section 1.4 ("Additional Compliance Information") of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Identify the material impact associated with this interpretation:

Clarification is needed to avoid applications of BAL-002-0 that would render the reserve requirement specified in R3.1 of BAL-002-0 (which calls for "enough Contingency Reserve to cover the most severe single Contingency") meaningless. The intent of BAL-002-0 is that all Contingencies greater than or equal to 80% of the most severe single Contingency constitute "Reportable Disturbances." *See* Section 1.4 of Part D of BAL-002-0 (where the "Additional Compliance Information" includes a definition of "Reportable Disturbance").

If a Balancing Authority were to experience a Contingency below the Reportable Disturbance level, it would be expected to recover ACE within 15 minutes, even though the literal words of R4 of BAL-002-0 do not say this. Conversely, if a Balancing Authority were to experience a Disturbance five times greater than its most severe single Contingency, it would be required to report this Disturbance, but would not be required to recover ACE within 15 minutes following a Disturbance of this magnitude.

Any other interpretation would result in treating BAL-002-0 as if it required Balancing Authorities and Reserve Sharing Groups to recover ACE (to zero or pre-Disturbance levels, as applicable) within the 15-minute Disturbance Recovery Period without regard to Disturbance magnitude. This is inconsistent with (a) the reserve requirement specified in R3.1 of BAL-002-0, (b) the text of Section 1.4 of Part D of BAL-002-0, and (c) the documented history of the development of BAL-002-0 (*see, e.g.,* Performance Standards Document, Version 3 (as accepted by NERC Resources Subcommittee on October 23, 2007), which provides in Section D, *Disturbance Control Standard, DCS*, that "An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.")

Furthermore, lack of clarity on the interpretation of this standard potentially has significant financial and operational impacts on all Balancing Authorities and Reserve Sharing Groups. If the standard is interpreted to require that ACE be returned to zero even for a Disturbance that exceeds the most severe single Contingency, a Balancing Authority could be required to take drastic operational actions, even when other measures of system reliability (voltage stability, normal frequency, operation within system operating limits, etc.) indicate otherwise.

Response:

The Balancing Authority Controls Standard Drafting Team was originally assigned to provide a response to the interpretation request. The original interpretation failed to achieve a two-thirds approval from the industry. NERC appointed a new IDT to develop this interpretation. On July 24, 2012, the team provided the following response to the questions raised:

Question 1: Although a Disturbance[2] that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group?

Response: The IDT agrees that the Disturbance would be excluded from compliance. The BAL-002 **Additional Compliance Information section** clearly states:

> Simultaneous Contingencies – Multiple contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, <u>the loss shall be reported</u>, <u>but excluded from compliance evaluation.</u>

For clarity the IDT would like to explain the Team's basis concerning some of the terminology used.

> **Most Severe Single Contingency (MSSC)** – this can be the loss of the BA's or RSG's single largest operating generator, or it can be a known common mode failure that causes more than one generator to fail when the contingency occurs; or it can be a firm transaction. Although Requirement R3.1 mandates an annual "review" that does not mean an annual value. Note that Requirement R3.1 determines a "prospective" MSSC. MSSC is a variable that the BA knows and operates to in real time. The largest operating generator is known and monitored by a BA. The largest known common mode failure is predefined for the BA; the largest single firm transaction is approved by the BA. Thus the BA knows its MSSC which can vary from hour to hour and minute to minute.
>
> To be clear a BA is responsible for the MSSC at all times (the MSSC value at any given time may be more or less than the annually identified prospective MSSC).
>
> An undefined "common mode" failure can occur but it is exempted from R4's requirement to meet the BA's or RSG's disturbance recovery criteria within the Disturbance Recovery Period. An undefined common mode failure (i.e. a disturbance that exceeds the MSSC) must be reported to allow the ERO to help ensure that it is not a continuing condition.

BAL-002 has two categories (1) Compliance and reporting (for Reportable Disturbances that must comply with the disturbance recovery criteria within the Disturbance Recovery Period) and (2) Reporting only (for specified disturbances and system conditions) events that are excluded from meeting Requirement R4

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[2] Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

requirement.

The **Compliance and reporting category** is designed to be used to accumulate all DCS events that are subject to compliance to BAL-002 Requirement R4 (i.e. recover ACE within 15 minutes). These include all single assets as well as all pre-defined common mode failures. The standard originally created R_i (the average percent recovery for a Reportable Disturbance) as a measure of the quarterly compliance for Reportable Disturbances. Where all events greater than 80% were mandatory to report and those less than 80% were permitted to be reported (thus encouraging reporting smaller events).

The **Reporting only category** is designed to track multiple contingency events that are not subject to Requirement R4. This category is designed to ensure that common mode (single point of failures) events are not missed. Thus if two or more contingencies repeatedly occur, the expectation was that the ERO would have the information to alert the BA that the two contingencies must be considered as a single event and thus considered as the MSSC.

The **Performance Standard Reference document** initially included with the DCS standard does states "Where RSGs exist, the Regional Reliability Council is to decide either to report on a BA basis or an RSG basis. If an RSG has dynamic membership then… required …to report on a BA basis.

Question 2: With respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, does the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency apply both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance?

Response: Requirement R5 is directed to RSGs, where RSG is defined in the NERC Glossary as:

> A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of Disturbance Control Performance, the Areas become a Reserve Sharing Group.

The standard provides flexibility to BAs regarding the use or non-use of RSGs (Requirement R1.1). Requirement R2 affords the members flexibility in how they organize themselves.

Requirement R1.1 allows, at the option of a BA, or RSG to take on all or part of the responsibilities that BAL-002 places on a BA. However, Requirement R5 allows a BA to "call for activation" of reserves [aka dynamic allocation of membership] moreover, there is no ad hoc recognition of such an RSG's multiple contingencies since a contingency in one BA may or not be referred to the RSG, and the simultaneous contingency in another BA is unknown.

The Technical Document does allow for a pre-acknowledged RSG to report on a composite basis. It can be interpreted that such a pre-acknowledged RSG entity assumes all of the obligations and rights afforded to a single BA and in that case such an RSG would be afforded the same Exclusions as the Exclusions afforded a BA.

In summary, the interpretation is as follows:

- The Standard was written to provide pre-acknowledged RSGs the same considerations as a single BA for purposes of exclusions from DCS compliance evaluation. Thus for a pre-acknowledged RSG the exclusion rules would be used in the same manner as they would be used for a single BA. This applies to both multiple contingencies occurring within one minute or less of each other being treated as a single Contingency and to Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period.

The standard, while recognizing dynamically allocated RSGs, does NOT provide the members of dynamically allocated RSGs exclusions from DCS compliance evaluation on an RSG basis. For members of dynamically allocated RSGs, the exclusions are provided only on a member BA by member BA basis.

Question 3: Clarify the meaning of the phrase "excluded from compliance evaluation" as used in Section 1.4 ("Additional Compliance Information") of Part D of BAL-002-0 and for purposes of the preceding statements, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), does BAL-002-0 require ACE to be recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Response: The **Additional Compliance Information section** clearly states:

Simultaneous contingencies – Multiple contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the Most Severe Single Contingency, <u>the loss shall be reported</u>, <u>but excluded from compliance evaluation.</u>

Although Requirement R3 does mandate that a BA or RSG activate sufficient Contingency Reserves to comply with DCS for every Reportable Disturbance, there is no requirement to comply with or even report disturbances that are below the Reportable Disturbance level. The averaging obligation does incent calculation and reporting of such lesser events.

If a Balancing Authority were to experience a Disturbance five times greater than its most severe single Contingency, it would be required to report this Disturbance, but would not be required to recover ACE within 15 minutes following a Disturbance of this magnitude.

An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency. Any other interpretation would result in treating BAL-002-0 as if it required Balancing Authorities and Reserve Sharing Groups to recover ACE (to zero or pre-Disturbance levels, as applicable) within the 15-minute Disturbance Recovery Period without regard to Disturbance magnitude. This is inconsistent with (a) the reserve requirement specified in R3.1 of BAL-002-0, (b) the text of Section 1.4 of Part D of BAL-002-0, and (c) the documented history of the development of BAL-002-0 (*see, e.g.,* Performance Standards Document, Version 3 (as accepted by NERC Resources Subcommittee on October 23, 2007), which provides in Section D, *Disturbance Control Standard, DCS*, that "An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.")

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Note: an Interpretation cannot be used to change a standard.

Request for an Interpretation of a Reliability Standard

Date submitted: September 2, 2009

Date accepted: September 2, 2009

Contact information for person requesting the interpretation:

Name: Northwest Power Pool Reserve Sharing Group, in care of Jerry Rust, Agent

Organization: Northwest Power Pool Reserve Sharing Group

Telephone: 503-445-1074

E-mail: jerry.rust@nwpp.org

Identify the standard that needs clarification:

Standard Number (include version number): BAL-002-0

Standard Title: Disturbance Control Performance

Identify specifically what requirement needs clarification:

Requirement Number and Text of Requirement:

B. Requirements

***

R4. A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:

R4.1. A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.

R4.2. The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.

***

R5. Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. *** Compliance may be demonstrated by either

of the following two methods:

R.5.1 The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

R.5.2. The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

***

D. **Compliance**

***

1.4 Additional Compliance Information

***

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

<u>Clarification needed</u>:

The Northwest Power Pool Reserve Sharing Group respectfully requests clarification as to whether:

(1) although a Disturbance[1] that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), the Disturbance is excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group;

(2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve

[1] Irrespective of cause, including a single event, simultaneous Contingencies, or non-simultaneous multiple Contingencies.

Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and

(3) the meaning of the phrase "excluded from compliance evaluation" as used in Section 1.4 ("Additional Compliance Information") of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Identify the material impact associated with this interpretation:

Clarification is needed to avoid applications of BAL-002-0 that would render the reserve requirement specified in R3.1 of BAL-002-0 (which calls for "enough Contingency Reserve to cover the most severe single Contingency") meaningless. The intent of BAL-002-0 is that all Contingencies greater than or equal to 80% of the most severe single Contingency constitute "Reportable Disturbances." *See* Section 1.4 of Part D of BAL-002-0 (where the "Additional Compliance Information" includes a definition of "Reportable Disturbance").

If a Balancing Authority were to experience a Contingency below the Reportable Disturbance level, it would be expected to recover ACE within 15 minutes, even though the literal words of R4 of BAL-002-0 do not say this. Conversely, if a Balancing Authority were to experience a Disturbance five times greater than its most severe single Contingency, it would be required to report this Disturbance, but would not be required to recover ACE within 15 minutes following a Disturbance of this magnitude.

Any other interpretation would result in treating BAL-002-0 as if it required Balancing Authorities and Reserve Sharing Groups to recover ACE (to zero or pre-Disturbance levels, as applicable) within the 15-minute Disturbance Recovery Period without regard to Disturbance magnitude. This is inconsistent with (a) the reserve requirement specified in R3.1 of BAL-002-0, (b) the text of Section 1.4 of Part D of BAL-002-0, and (c) the documented history of the development of BAL-002-0 (*see, e.g.,* Performance Standards Document, Version 3 (as accepted by NERC Resources Subcommittee on October 23, 2007), which provides in Section D, *Disturbance Control Standard, DCS*, that "An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.")

Furthermore, lack of clarity on the interpretation of this standard potentially has significant financial and operational impacts on all Balancing Authorities and Reserve Sharing Groups. If the standard is interpreted to require that ACE be returned to zero even for a Disturbance that exceeds the most severe single Contingency, a Balancing Authority could be required to take drastic operational actions, even when other measures of system reliability (voltage stability, normal frequency, operation within system operating limits, etc.) indicate otherwise.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2009-19 Interpretation of BAL-002-0 NWPP Reserve Sharing Group

Recirculation Ballot Window Now Open: September 28 – October 8, 2012

Now Available

A recirculation ballot for the Interpretation of BAL-002-0 - Disturbance Control Performance Requirements R4 and R5 for NWPP Reserve Sharing Group is open through **8 p.m. Eastern on Monday, October 8, 2012**.

Instructions

Members of the ballot pool associated with this project may log in and submit their vote for the interpretation by clicking here.

Next Steps

The Interpretation of BAL-002-0 will be presented to the Board of Trustees for adoption in November 2012 and then filed with the appropriate regulatory authorities.

Background

Northwest Power Pool Reserve Sharing Group (NWPP) submitted a request for interpretation asking for clarification in three specific areas of BAL-002-0 Disturbance Control Performance. The specific areas NWPP is requesting clarification on are:

1)although a Disturbance that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group; and

2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when:

(a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group, and

(b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and

3) the meaning of the phrase "excluded from compliance evaluation" as used in Section 1.4 ("Additional Compliance Information") of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Additional information is available on the project page.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Monica Benson, Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

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

Standards Announcement

Project 2009-19 – Interpretation of BAL-002-0 - NWPP Reserve Sharing Group

Recirculation Ballot Results

Now Available

A recirculation ballot for the Interpretation of BAL-002-0 - Disturbance Control Performance Requirements R4 and R5 for NWPP Reserve Sharing Group concluded on Monday, October 8, 2012.

Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results.

Ballot Results
Quorum: 85.11%
Approval: 90.34%

Next Steps

The interpretation will be presented to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Background

Northwest Power Pool Reserve Sharing Group (NWPP) submitted a request for interpretation asking for clarification in three specific areas of BAL-002-0 Disturbance Control Performance. The specific areas NWPP is requesting clarification on are; 1) although a Disturbance that exceeds the most severe single Contingency must be reported by the Balancing Authority or Reserve Sharing Group (as applicable), is the Disturbance excluded from compliance evaluation for the applicable Balancing Authority or Reserve Sharing Group; 2) with respect to either simultaneous Contingencies or non-simultaneous multiple Contingencies affecting a Reserve Sharing Group, the exclusion from compliance evaluation for Disturbances exceeding the most severe single Contingency applies both when (a) all Contingencies occur within a single Balancing Authority member of the Reserve Sharing Group and (b) different Balancing Authorities within the Reserve Sharing Group experience separate Contingencies that occur simultaneously, or non-simultaneously but before the end of the Disturbance Recovery Period following the first Reportable Disturbance; and 3) the meaning of the phrase "excluded from compliance evaluation" as used in Section 1.4 ("Additional Compliance Information") of Part D of BAL-002-0 and for purposes of the preceding statements is that, with respect to Disturbances that exceed the most severe single Contingency for a Balancing Authority or Reserve Sharing Group (as applicable), a violation of BAL-002-0 does not occur even if ACE is not recovered within the Disturbance Recovery Period (15 minutes unless adjusted pursuant to BAL-002-0, R4.2).

Additional information is available on the project page.

Standards Development Process

The Standards Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

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Ballot Results	
Ballot Name:	Project 2009-19 BAL-002 Recirculation Ballot
Ballot Period:	9/28/2012 - 10/8/2012
Ballot Type:	Initial
Total # Votes:	303
Total Ballot Pool:	356
Quorum:	**85.11 % The Quorum has been reached**
Weighted Segment Vote:	90.34 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative		Negative		Abstain	No
			# Votes	Fraction	# Votes	Fraction	# Votes	Vote
1 - Segment 1.	94	1	62	0.849	11	0.151	8	13
2 - Segment 2.	10	1	9	0.9	1	0.1	0	0
3 - Segment 3.	81	1	55	0.887	7	0.113	7	12
4 - Segment 4.	25	1	16	0.941	1	0.059	3	5
5 - Segment 5.	75	1	49	0.961	2	0.039	9	15
6 - Segment 6.	52	1	36	0.947	2	0.053	9	5
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	10	0.6	6	0.6	0	0	1	3
9 - Segment 9.	2	0.2	2	0.2	0	0	0	0
10 - Segment 10.	7	0.6	4	0.4	2	0.2	1	0
Totals	**356**	**7.4**	**239**	**6.685**	**26**	**0.715**	**38**	**53**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Ameren Services	Kirit Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Negative	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Corp.	Scott J Kinney	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Gregory S Miller	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	

1	Beaches Energy Services	Joseph S Stonecipher	Negative	
1	Black Hills Corp	Eric Egge	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Abstain	
1	Dayton Power & Light Co.	Hertzel Shamash		
1	Dominion Virginia Power	Michael S Crowley		
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Dennis Malone	Affirmative	
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	FortisBC	Curtis Klashinsky		
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Bernard Pelletier	Abstain	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	
1	Kansas City Power & Light Co.	Michael Gammon		
1	Lakeland Electric	Larry E Watt		
1	Lee County Electric Cooperative	John W Delucca	Affirmative	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	
1	Manitoba Hydro	Joe D Petaski	Affirmative	
1	MEAG Power	Danny Dees		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine	Affirmative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Affirmative	
1	Ohio Valley Electric Corp.	Robert Mattey	Negative	
1	Oklahoma Gas and Electric Co.	Marvin E VanBebber	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Ryan Millard	Abstain	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Progress Energy Carolinas	Brett A. Koelsch		
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Public Utility District No. 2 of Grant County, Washington	Rod Noteboom	Affirmative	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	

1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L Blackwell	Affirmative	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Abstain	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southern Illinois Power Coop.	William Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo	Affirmative	
1	Turlock Irrigation District	Esteban Martinez	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Ken A Gardner	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon	Affirmative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Affirmative	
3	AEP	Michael E Deloach	Negative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Ameren Services	Mark Peters	Affirmative	
3	APS	Steven Norris	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Negative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Clewiston	Lynne Mila		
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy	Richard Blumenstock	Affirmative	
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Abstain	
3	El Paso Electric Company	Tracy Van Slyke	Affirmative	
3	FirstEnergy Energy Delivery	Stephan Kern	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Grays Harbor PUD	Wesley W Gray	Affirmative	
3	Great River Energy	Brian Glover	Affirmative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner		
3	Lakeland Electric	Mace D Hunter		

3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Daniel D Kurowski	Abstain	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Municipal Electric Authority of Georgia	Steven M. Jackson		
3	Muscatine Power & Water	John S Bos	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	
3	Ocala Electric Utility	David Anderson		
3	Oklahoma Gas and Electric Co.	Gary Clear		
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Abstain	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Abstain	
3	Pepco Holdings, Inc.	Mark R Jones	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 1 of Chelan County	Steve Wickel	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	David B Coher		
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Turlock Irrigation District	James Ramos	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	American Municipal Power	Kevin Koloini	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Negative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of Clewiston	Kevin McCarthy		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Abstain	
4	Consumers Energy	David Frank Ronk	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney		
4	Fort Pierce Utilities Authority	Cairo Vanegas		
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke	Affirmative	
4	Northern California Power Agency	Tracy R Bibb		
4	Ohio Edison Company	Douglas Hohlbaugh		
4	Old Dominion Electric Coop.	Mark Ringhausen	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	

4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Turlock Irrigation District	Steven C Hill	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Negative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino		
5	Calpine Corporation	Phillip Porter	Affirmative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty		
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	Cleco Power	Stephanie Huffman	Affirmative	
5	Colorado Springs Utilities	Jennifer Eckels	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Deseret Power	Philip B Tice Jr	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Detroit Renewable Power	Marcus Ellis		
5	Duke Energy	Dale Q Goodwine	Negative	
5	El Paso Electric Company	David Hawkins	Affirmative	
5	Essential Power, LLC	Patrick Brown	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann		
5	Great River Energy	Preston L Walsh	Affirmative	
5	Hydro-Québec Production	Roger Dufresne		
5	Imperial Irrigation District	Marcela Y Caballero	Abstain	
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough		
5	Lakeland Electric	James M Howard		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego		
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	Northern Indiana Public Service Co.	William O. Thompson	Affirmative	
5	Oklahoma Gas and Electric Co.	Kim Morphis	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	PacifiCorp	Sandra L. Shaffer	Affirmative	
5	Platte River Power Authority	Roland Thiel		
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PowerSouth Energy Cooperative	Tim Hattaway	Abstain	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	Proven Compliance Solutions	Mitchell E Needham	Abstain	
5	Public Utility District No. 1 of Chelan County	John Yale	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega		
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	

5	Southern California Edison Company	Denise Yaffe		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	Turlock Irrigation District	Marty Rojas	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer	Abstain	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Abstain	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Affirmative	
6	Colorado Springs Utilities	Lisa C Rosintoski	Affirmative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Affirmative	
6	Constellation Energy Commodities Group	Donald Schopp	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy	Greg Cecil	Affirmative	
6	El Paso Electric Company	Tony Soto	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery		
6	Florida Municipal Power Pool	Thomas Washburn		
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Great River Energy	Donna Stephenson	Affirmative	
6	Imperial Irrigation District	Cathy Bretz	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Abstain	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Kelly Cumiskey	Abstain	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	John Jamieson		
6	PPL EnergyPlus LLC	Elizabeth Davis	Abstain	
6	Progress Energy	John T Sturgeon	Abstain	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	William T Moojen	Affirmative	
6	Southern California Edison Company	Lujuanna Medina	Abstain	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Turlock Irrigation District	Amy Petersen	Affirmative	
6	Westar Energy	Grant L Wilkerson	Affirmative	
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	

6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
8		James A Maenner		
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Affirmative	
8	Ascendant Energy Services, LLC	Raymond Tran	Affirmative	
8	Energy Mark, Inc.	Howard F. Illian	Affirmative	
8	JDRJC Associates	Jim Cyrulewski	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	National Association of Regulatory Utility Commissioners	Diane J. Barney	Affirmative	
9	Oregon Public Utility Commission	Jerome Murray	Affirmative	
10	Midwest Reliability Organization	William S Smith	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Negative	
10	SERC Reliability Corporation	Carter B. Edge	Negative	
10	Southwest Power Pool RE	Emily Pennel	Abstain	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Account Log-In/Register

Exhibit D

Interpretation Drafting Team Roster for NERC Standards Development Project 2009-1

Project 2009-19 Interpretation of BAL-002-0 for NWPP
Drafting Team Roster

Name and Title Affiliation Contact Info	Bio
Albert DiCaprio - Chair PJM 955 Jefferson Avenue Valley Forge Corporate Center Norristown, PA 19403-2497 dicapram@pjm.com	Albert DiCaprio has been employed by PJM since 1970. His experience at PJM includes System Operations Department in which he helped developed PJM generation control program, PJM's Accounting for regulation program and PJM's Fuel Supply Emergency procedures; in the System Performance Department he initiated performance monitoring and benchmarking programs, and PJM's Energy by Fuel type tracking system; and he helped launch PJM's first retail customer support program. As Senior Strategist, Mr. DiCaprio provides analysis and support for PJM positions on NERC standards and FERC initiatives. Mr. DiCaprio is a current member of the Standards Committee and has served on various NERC committees most notably as Chairman of the Performance Subcommittee when the first Control Performance Standard was approved and he served on the Task Force whose efforts led to the development of the NERC Functional Model. Mr. DiCaprio serves as the chairman of the ISO/RTO's Standards Review Committee who review and comment on NERC Reliability Standards, NAESB Business Practices and FERC initiatives related to reliability standards. Active in the IEEE, he is a senior member and has published various papers and has served on Technical Activities committees for two Joint IEEE-CIGRE conferences. Internationally, Mr. DiCaprio serves as the chairman of the International Group on Comparison of Transmission Operation Practices. Mr. DiCaprio has been part of CIGRE's initiative into Energy Markets and has been active with Study Committee C5 (Markets and Regulation) since its beginning in 2000 and received CIGRE 2009 Technical Committee Award for his contributions to the Study Committee. He is also active in a Joint Working Group with Markets and Operations, and Working groups on System Design (WG C5-7) and on Integration of Renewable resources and Demand-side Management (WG C5-11). He has a bachelor's in electrical engineering from Drexel University in Philadelphia and a Master's in System Operations from the University of Pennsylvania.
Gerald Beckerle Ameren Sr Transmission Operations Supervisor Transmission Operations T 314.554.6413	Gerald D. Beckerle, Senior Transmission Operations Supervisor, Ameren Services, St. Louis, MO, has a BSEE from the University of Missouri, Columbia. He has been with Ameren for 32 years, 25 of those years in System Operations, which has been or is currently responsible for Transmission, Generation, and daily interchange. Current activities include:

GBeckerle@ameren.com	SERC Operating Committee Chairman NERC Resources Subcommittee Vice-Chairman NERC Operating Committee member and serving on the committee's executive committee NERC Balancing Authority Reliability Based Controls Standard Drafting Team member NERC Frequency Response Standard Drafting Team Contributor Past Activities included: Balancing Authority Controls SAR and SDT member prior to merging into the BARC SDT. Midwest Reserve Sharing Group representative for Ameren RFC Version Zero Standards Drafting Team member MAIN Operating Reserve Subcommittee member
Howard F. Illian President Energy Mark, Inc. 334 Satinwood Ct. N. Buffalo Grove, Illinois 60089 (847) 913-5491 howard.illian@energymark.com	Howard F. Illian graduated from Carnegie Institute of Technology (Carnegie-Mellon University) in 1970 with a B.S. in Electrical Engineering. From 1970 until 1982 he worked for ComEd in the field of Operations Research, and was Supervisor, Economic Research and Load Forecasting from 1976 until he was reassigned to Bulk Power Operations in 1982 where he was Technical Services Director when he retired in 1998. He is now President of Energy Mark, Inc., a consulting firm specializing in the commercial relationships required by restructuring. He has authored numerous papers, and has testified as an expert witness before the Illinois EPA, the Federal EPA, the Illinois Commerce Commission and the Public Utility Commission of Texas. He has developed and applied several new mathematical techniques for use in simulation and decision making. He has served on the NERC Performance Subcommittee, the Interconnected Operations Services Implementation Task Force, the Joint Inadvertent Interchange Task Force, and the NAESB Inadvertent Interchange Payback Task Force. Recent work includes significant contributions to the development of new NERC Control Performance Standards including the Balancing Authority Ace Limit and a suggested mathematical foundation for control based on classical statistics. His current research concentrates on the development of technical definitions for Ancillary or Reliability Services including frequency response and their market implementation.

Guy Quintin Ingénieur Chef – Centre de conduite du réseau Programmation et Contrôle du réseau Direction CMÉ Hydro-Québec TransÉnergie Tel: 514-289-2211 #3150 cell: 514-793-9838 Quintin.Guy@hydro.qc.ca	Mr. Quintin studied at the University of Montreal and graduated in Electrical Engineering (B.S. Eng.) in 1981. Since then, he has worked at Hydro-Québec: two years in the Distribution department, seven years at the Regional Operations in the Eastern Quebec and 20 years as an Operation Engineer at the System Control Center in Montreal. He has been a member of the NPCC Control Performance Working Group (CO-1) for five years. Since 2010, he has been a manager of the operators in the Control Room. He is a member of the NPCC System Operations Managers Working Group and the NERC Balancing Authority Reliability-based Control Standard Drafting Team.
Darrel Richardson Standards Developer North American Electric Reliability Corporation 3353 Peachtree Road NE, Suite 600 – North Tower Atlanta, GA 30326 609-613-1848 cell darrel.richardson@nerc.net	Darrel Richardson joined the NERC staff as a Standards Developer. In this role he facilitates and provides guidance to drafting teams in the development of technically excellent and timely reliability standards for the reliable operation and planning of the bulk power system. Darrel began his career with NERC in November 2007. Darrel has extensive experience in the utility industry having spent over 37 years with Illinois Power Company. In his tenure at Illinois Power he held several different positions in the Engineering, Planning and Operations groups. Among the position he has held are Transmission Coordinator, Generation Coordinator, Manager Wholesale Marketing, Manager Wholesale Marketing and Trading, Director Generation Control and Manager Compliance.