UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Electric Reliability Organization Interpretation Of Specific Requirements of the Disturbance Control Performance Standard	**)))**	**Docket Nos. RM13-6-000**

COMMENTS OF THE
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION
IN RESPONSE TO NOTICE OF PROPOSED RULEMAKING

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July 8, 2013

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Electric Reliability Organization Interpretation	**)**	**Docket Nos. RM13-6-000**
Of Specific Requirements of the Disturbance	**)**	
Control Performance Standard	**)**	

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IN RESPONSE TO NOTICE OF PROPOSED RULEMAKING

The North American Electric Reliability Corporation ("NERC")[1] hereby provides these comments in response to the Federal Energy Regulatory Commission's ("FERC" or the "Commission") May 16, 2013, Notice of Proposed Rulemaking ("NOPR")[2] proposing to remand the proposed interpretation of Reliability Standard BAL-002-1, Disturbance Control Performance, Requirements R4 and R5 addressing whether Balancing Authorities and Reserve Sharing Groups are subject to enforcement actions for failing to restore Area Control Error within the 15-minute Disturbance Recovery Period for Reportable Disturbances that exceed the most severe single Contingency.[3]

I. <u>Executive Summary</u>

NERC urges the Commission to accept the proposed interpretation as submitted. The question presented by the NOPR is whether the language with respect to Simultaneous Contingencies that states if the combined magnitude of multiple Contingencies exceeds the most

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[1] The Federal Energy Regulatory Commission certified NERC as the electric reliability organization ("ERO") in its order issued on July 20, 2006, in Docket No. RR06-1-000. *North American Electric Reliability Corporation*, 116 FERC ¶ 61,062 (2006).

[2] *Electric Reliability Organization Interpretation of Specific Requirements of the Disturbance Control Performance Standard*, 143 FERC ¶ 61,138 (2013)("NOPR"). 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.

[3] The Commission proposed to remand the proposed interpretation because the Commission states that it "changes the requirements of the Reliability Standard, thereby exceeding the permissible scope for interpretations." *Id.* at P 1.

severe single Contingency, "<u>the loss shall be reported, but excluded from compliance evaluation</u>" ("Exclusion Language") modifies Requirements R3 and R4. The proposed interpretation answers this question affirmatively. The Commission's NOPR rejects such a reading as unnatural and states that this language modifies the Levels of Non-Compliance section.[4] The terms of Reliability Standard BAL-002 are therefore subject to interpretation because the phraseology can support reasonable differences of opinion as to the meaning of the words employed and the obligations undertaken.[5] Consistent with the tenets of statutory and regulatory construction, the proposed NERC interpretation reads all of the terms of the Standard together such that every provision within the Standard is given effect and construed in a manner that is consistent with the purpose and content of the document in its entirety.[6]

The proposed NERC interpretation is (1) consistent with the plain meaning of Requirement R4 and gives effect to all of the terms, (2) consistent with the historical evolution of the NERC Operating Policies into the mandatory and enforceable NERC Reliability Standards, and (3) necessary for reliability. Consistent with the statutory framework of Section 215 of the Federal Power Act, the Commission should defer to NERC's interpretation of the BAL-002 Reliability Standard. Rather than remanding NERC's proposed interpretation, the Commission should approve the interpretation and encourage NERC and the electric industry to move

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[4] NOPR at P 22 ("A more natural reading of the standard is that the exclusion language in the Additional Compliance Information section applies to the Levels of Non-Compliance section contained in BAL-002-1, Part D, Section 2…").

[5] *See e.g., Koch Gateway Pipeline Co. v. Federal Energy Regulatory Commission*, 136 F.3d 810, 814 (D.C. Cir. 1998); *Fashion House, Inc.v. Kmart Corp.,* 892 F.2d 1076, 1092 (1st Cir. 1989)("language is usually considered ambiguous where an agreement's terms are inconsistent on their face or where the phraseology can support reasonable difference of opinion as to the meaning of the words employed and obligations undertaken.").

[6] *See Transmission Relay Loadability Reliability Standard*, 134 FERC 61,127 at P 25 (2011)("we note that it is a maxim of statutory construction that each part or section of a statute should be construed in connection with every other part or section so as to produce a harmonious whole."); citing Shell Oil Company, et al., In the Matter of the Transportation of Liquid and Liquefiable Hydrocarbons by Natural Gas Pipelines, 22 FERC ¶ 61,013, at 61,024 (1983); *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, 139 FERC ¶ 61,132 at P 132 (2012) citing Deal v. United States, 508 U.S. 129, at 132 (1993)("It is a 'fundamental principle of statutory construction (and, indeed, of language itself) that the meaning of a word cannot be determined in isolation, but must be drawn from the context in which it is used.'").

forward expeditiously with revisions to BAL-002 so as to eliminate any potential for further confusion.

II. Notices and Communications

Notices and communications with respect to this filing may be addressed to the following:[7]

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[7] Persons to be included on the Commission's service list are indicated with an asterisk. NERC requests waiver of 18 C.F.R. § 385.203(b) to permit the inclusion of more than two people on the service list.

III. Background

A. Purpose of Reliability Standard BAL-002, Disturbance Control Performance

The purpose of the BAL-002 Disturbance Control Performance Reliability Standard is to ensure a Balancing Authority is able to utilize its Contingency Reserve[8] to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. During a Disturbance, controls cannot usually maintain Area Control Error ("ACE") within the criteria for normal load variation. Balancing Authorities, alone or collectively through Reserve Sharing Groups, are expected to activate Contingency Reserve to cause recovery of ACE magnitude within fifteen minutes following the start of a 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.

B. Language of Reliability Standard BAL-002, Disturbance Control Performance

Reliability Standard BAL-002-1 has six Requirements. Most relevant to the discussion in the NOPR of the proposed interpretation, Requirements R3 and R4 provide:

> 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

[8] 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."

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.

Also relevant to the proceeding is the Additional Compliance Information language in Part D of BAL-002-1, which includes:

Reportable Disturbances – Reportable Disturbances are contingencies that are greater than or equal to 80% of the most severe single Contingency. . .

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.

IV. Comments

As explained below, the proposed interpretation of Reliability Standard BAL-002 is (1) consistent with the plain meaning of Requirement R4 and gives effect to all of its terms, (2) consistent with the historical evolution of the NERC Operating Policies into the mandatory and enforceable NERC Reliability Standards, and (3) necessary for reliability. Furthermore, the Commission should defer to NERC's interpretation consistent with the statutory framework of Section 215 of the Federal Power Act.

A. The Proposed Interpretation of Reliability Standard BAL-002 is Consistent with the Plain Meaning of Requirement R4 of the BAL-002 Reliability Standard and Gives Effect to All of the Terms

The proposed interpretation is consistent with the plain meaning of Requirement R4 of the BAL-002 Reliability Standard and gives meaning to all of the terms in the Standard. Requirement R3 requires entities to "activate sufficient Contingency Reserve to comply" with BAL-002. Requirement R3.1 specifies the *minimum* amount of Contingency Reserve that entities must carry. Requirement R4, as interpreted by the NERC drafting team, specifies the *maximum* amount of Contingency Reserve that entities are obligated to carry by the Standard.

The Commission's suggested interpretation is impractical and would lead to actions that are counter to reliability. From a practical perspective, it would be impossible to require Responsible Entities to carry enough Contingency Reserves to meet any potential event and this would result in entities operating at levels that are uneconomic and burdensome. As explained below, this could also result in entities shedding load unnecessarily.[9] BAL-002 is designed to require entities to carry enough Contingency Reserves to meet reasonably foreseeable events, not every possible event.

The proposed interpretation does not *change* a Requirement of the Reliability Standard as the Commission asserts in the NOPR,[10] rather the interpretation adds clarity regarding the meaning of the language of the Reliability Standard. The term "Reportable Disturbance" is defined in the *NERC Glossary of Terms Used in Reliability Standards*, however, it is also defined in Part D, Section 1.5 of the BAL-002 Reliability Standard. Under the rule of statutory construction, when a conflict exists between a specific law and a general law, the provisions of the specific law prevail. In this instance, the more specific Exclusion Language, which appears

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[9] *See* Section III.E.
[10] NOPR at P 18.

directly below the term "Reportable Disturbance" within the BAL-002 Reliability Standard, correctly influences the meaning of the term within the context of the Standard. This interpretation is also consistent with the record.

As explained herein, historically, an "excludable disturbance" is a "disturbance whose magnitude was greater than the magnitude of the most severe single contingency."[11] The meaning of the phrase "excluded from compliance evaluation" in the Exclusion Language is synonymous with the term "excludable disturbance" in the *NERC Performance Standards Reference Document*.

The proposed interpretation harmonizes and gives reasonable meaning and effect to all of the provisions of the BAL-002 Reliability Standard. While an interpretation may be an awkward procedural vehicle to provide this clarity, as compared to a revision to the BAL-002 Reliability Standard, the meaning and intent of the BAL-002 standard is widely-known and understood in the industry, as evidenced by the overwhelming approval rating of the interpretation.[12] In fact, it is the Commission's proposed reading of BAL-002 that would constitute a *change* in the way that the Reliability Standard is commonly understood.

B. The Proposed NERC Interpretation is Consistent with the Course of Performance

The course of performance demonstrates that the proposed NERC interpretation does not change the BAL-002 Reliability Standard. While a Reliability Standard is not a contract, as in contract law, the course of performance can be persuasive evidence of the agreed-upon intent of

[11] *See* Attachment B, NERC Performance Standards Reference Document.

[12] The interpretation received an approval rating of 90.34%. NERC notes that revisions to the BAL-002 Reliability Standard are currently in development as part of Project 2010-14.1. Additional information is *available here*: http://www.nerc.com/pa/Stand/Pages/Project2010-14-1-Phase-1-of-Balancing-Authority-RBC.aspx.

a Reliability Standard. The proposed interpretation is consistent with the manner in which the electrical system is actually operated.[13]

For example, the WECC Reliability Management System ("RMS") Reporting Instructions[14] indicated that meeting the Disturbance Recovery Criterion was required for all Disturbances; however, the actual Reporting Form[15] for DCS was divided into two sections, one for Reportable Disturbances not greater than the most severe single Contingency, and one for Disturbances greater than the most severe single Contingency. The second section was footnoted to indicate it was not a performance issue, and was being completed for information only. The performance for Disturbances greater than the most severe single Contingency was not included in the averages used to determine compliance. This persuasively demonstrates that the proposed NERC interpretation is how the BAL-002 Reliability Standard was *meant* to work and how it *worked in actuality*.[16]

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[13] *See e.g.*, PJM Training Materials, NERC Reliability Coordination Refresher, at Slide 43 ("Multiple contingencies occurring within one minute or less of each other are treated as a single contingency*
-If the combined magnitude of the multiple contingencies exceeds the most severe single contingency, the loss will be reported, but excluded from the quarterly compliance evaluation because the entire amount cannot be recovered within the 15-minute time period") *available at* http://www.pjm.com/~/media/training/core-curriculum/ip-nerc-stand/nerc-reliability-refresher.ashx.

[14] The reporting instructions can be found at the following link (see page 8): http://www.wecc.biz/library/WECC%20Documents/Reliability%20Management%20System/4%20-%20Reporting%20Instructions%20and%20Compliance%20Standards/RMS%20Reporting%20Instructions%20Phase%201.pdf.

[15] The reporting form can be found in a spreadsheet available at the following link (see tab A.2): http://www.wecc.biz/library/WECC%20Documents/Forms/AllItems.aspx?RootFolder=%2flibrary%2fWECC%20Documents%2fReliability%20Management%20System&FolderCTID=0x012000278A29140A43884799CB122F821DFD01.

[16] *See e.g.*, *United Illuminating Co. v. Dominion Energy*, 121 FERC ¶ 61,043 at P 36 (2007) ("Course of performance under a contract is considered the most persuasive evidence of the parties' agreed intent.").

C. The Commission's Suggested Reading of BAL-002 Would Render Requirement R3 Meaningless

The Commission's suggested reading of BAL-002-1 that the Exclusion Language applies to the Levels of Non-Compliance section in BAL-002-1, Part D, Section 2,[17] would render meaningless portions of the BAL-002-1 Reliability Standard and should therefore be avoided.[18] The Commission proposes to interpret the Requirements of BAL-002 to require an entity to carry enough Contingency Reserve to meet any event, regardless of magnitude. Such a reading renders the minimum requirement of Requirement R3 superfluous and is inconsistent with the structure and intent of the BAL-002 Reliability Standard.

Furthermore, the Commission's interpretation reaches an illogical result. If the Exclusion Language were to apply only to the Levels of Non-Compliance section, an entity would be able to exclude an event that exceeds the most severe single Contingency from the evaluation of whether an upward adjustment in Contingency Reserves is warranted but would simultaneously be in violation of a Requirement (R3) that requires entities to "activate *sufficient* Contingency Reserve"[19] to comply with the BAL-002 Reliability Standard. The purpose of requiring entities to increase their Contingency Reserve obligations based on compliance with the BAL-002 Reliability Standard is to ensure that entities carry a sufficient level of reserves to meet expected potential Contingencies.

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17 *See* NOPR at P 22.

18 *See e.g.*, *Tennessee Gas Pipeline Co. v. FERC*, 17 F.3d 98, 103 (5th Cir. 1994)("the goal of contract interpretation is to determine the parties' intentions by harmonizing and giving effect to each provision within the contract such that none is rendered meaningless."). *See, e.g.*, Restatement (Second) of Contracts § 203(a), comment b (1979)(contract should be interpreted as a whole, with no part assumed to be superfluous); *Brinderson-Newberg Joint Venture v. Pacific Erectors, Inc.*, 971 F.2d 272, 278-79 (9th Cir. 1992) (contract should be interpreted to give meaning to each of its provisions); *Hawthorne Land Company v. U.S.*, 309 F.3d 888 (2002); *Cruden v. Bank of New York*, 957 F.2d 961, 976 (2d Cir. 1992) ("The entire contract must be considered, and all parts of it reconciled, if possible, in order to avoid an inconsistency.").

19 Emphasis added.

D. The Proposed Interpretation of Reliability Standard BAL-002 is Consistent with the Historical Development of the NERC Reliability Standards

As explained herein, Reliability Standard BAL-002 is based on NERC Operating Policy 1. The Commission's reading of the proposed interpretation is inconsistent with the historical evolution of Reliability Standard BAL-002 and a reading of the Standard as an integrated whole.

1. History of Reliability Standard BAL-002, Disturbance Control Performance

NERC was formed as a voluntary electric reliability organization shortly after the 1965 blackout in the northeastern United States and eastern Canada. Since its inception, NERC has adopted operating policies and planning standards to ensure the reliability of the bulk power system in North America. In response to the blackout of August 2003, and anticipating an eventual transition to the ERO, NERC transformed its existing operating policies and planning standards into Version 0 Reliability Standards, which became effective on April 1, 2005. BAL-002 was originally incorporated into Operating Policy 1—Generation Control and Performance.

Operating Policy 1consisted of seven subsections which were incorporated into mandatory and enforceable NERC Reliability Standards and various reference documents: (A) Control Performance Standard; (B) Disturbance Control Standard; (C) Frequency Response and Bias; (D) Time Control Standard; (E) Automatic Generation Control Standard; (F) Inadvertent Interchange Standard; and (G) Surveys Standard.[20] Section (B) Disturbance Control Standard was incorporated into Reliability Standard BAL-002. A mapping document illustrating how the components of Operating Policy 1 were incorporated into the Version 0 Reliability Standards is

[20] Section (A) Control Performance Standard was incorporated into Reliability Standard BAL-001; Section (B) Disturbance Control Standard was incorporated into Reliability Standard BAL-002; Section (C) Frequency Response and Bias was incorporated into Reliability Standard BAL-003; Section (D) Time Control Standard was incorporated into Reliability Standard BAL-004; Section (E) Automatic Generation Control Standard was incorporated into Reliability Standard BAL-005; Section (F) Inadvertent Interchange Standard was incorporated into Reliability Standard BAL-006; and Section (G) Surveys Standard was incorporated into various documents- the Area Interchange Error Survey Training Document, the Frequency Response Characteristic Survey Training Document, and Performance Standard Reference Document.

included as **Attachment A**. Section (B) Disturbance Control Standard consisted of five separately numbered sections and was incorporated into Reliability Standard BAL-002 as follows:

- The introductory statement regarding Reserve Sharing Groups was incorporated into Requirement R1.

- Section 1 (Contingency Reserves) and sub-sections 1.1 and 1.2 were incorporated into Requirement R2.

- Section 2 (Contingency Reserve to meet Disturbance Control Standard) and sub-section 2.1 were incorporated into Requirement R3.

- Sections 2.2 and sub-sections 2.2.1 and 2.2.2 were incorporated into Requirement R4.
    - (2.2 to BAL-002, R4)
      2.2. Disturbance Control Standard Compliance. When a CONTROL AREA or RESERVE SHARING GROUP experiences a REPORTABLE DISTURBANCE (SEE 2.4), it is compliant with the Disturbance Control Standard when the DISTURBANCE RECOVERY CRITERION is met within the DISTURBANCE RECOVERY PERIOD. Each CONTROL AREA or RESERVE SHARING GROUP shall meet the Disturbance Control Standard (DCS) 100% of the time for REPORTABLE DISTURBANCES.

    - (2.2.1 to BAL-002, R4)
      2.2.1. DISTURBANCE RECOVERY CRITERION. The CONTROL AREA shall return its ACE to zero if its ACE just prior to the DISTURBANCE was positive or equal to zero. For negative initial ACE values just prior to the DISTURBANCE, the ACE must return to its pre-disturbance value. The default performance criterion described above may be adjusted to better suit the needs of an INTERCONNECTION based on analysis approved by the NERC Resources Subcommittee and the NERC Operating Committee.
    - (2.2.2 to BAL-002, R4)
      2.2.2. DISTURBANCE RECOVERY PERIOD. 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 Resources Subcommittee and the NERC Operating Committee.

- Section 2.3 and sub-sections 2.3.1and 2.3.2 were incorporated into Requirement R5.
    - (2.3 to BAL-002, R5)
      2.3. RESERVE SHARING GROUP. Each RESERVE SHARING GROUP shall comply with the Disturbance Control Standard. A RESERVE SHARING GROUP shall be considered in a 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 condition but does not call for reserve activation from other members of the RESERVE SHARING GROUP, then that member shall report as a single CONTROL AREA.) Compliance may be demonstrated by either of the following two methods:

- (2.3.1 to BAL-002, R5)
  2.3.1. Group compliance to Disturbance Control Standard. 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.
- (2.3.2 to BAL-002, R5)
  2.3.2. Group member compliance to Disturbance Control Standard. 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. [See Requirement 2.2.2 above.]

- Section 2.4 (Reportable Disturbances) through Section 2.5.3 were incorporated into the supporting notes.
  - (2.4 through 2.5.3 were moved to BAL-002, Supporting Notes)

  2.4. Reportable Disturbances. REPORTABLE DISTURBANCES are contingencies that are greater than or equal to 80% of the MOST SEVERE SINGLE CONTINGENCY loss. Regions 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.

  2.5. Treatment of Multiple Contingencies.
  - **2.5.1. 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 proposed interpretation of the BAL-002 Reliability Standard focuses on how the language in what was formerly Sections 2.4 and 2.5.1 of Operating Policy 1 (now included in BAL-002, Part

D, (Additional Compliance Information), Section 1.5) modifies the language in what was formerly Sections 2.2 through 2.3 (now BAL-002 Requirements R4 and R5).

2. <u>The Historical Record Supports the Proposed Interpretation</u>

The original and natural reading of the Exclusion Language is apparent on the face of Operating Policy 1. The fact that Sections 2.4 through 2.5.3 of the NERC Operating Policy are supposed to be read to modify the immediately preceding sections (Sections 2.2 through 2.3.2) is plainly apparent. Sections 2.2 through 2.2.2 became Requirement R4 of BAL-002. Sections 2.3 through 2.3.2 became Requirement R5 of BAL-002. Section 2.4 through 2.5.3 of the NERC Operating Policy were moved to Part D (Additional Compliance Information) of BAL-002. The intent of the parties is clear in the language of the Reliability Standard itself, its purpose, and the circumstances of its execution and performance.[21]

As additional support for the historical evolution of BAL-002, included as **Attachment B** is the *NERC Performance Standards Reference Document*, which was intended to provide readers with a better understanding of the balancing-related standards, including the Disturbance Control Standard. The *NERC Performance Standards Reference Document* includes five sub-parts for "Reportable Disturbances" and defines an "excludable disturbance" as "a disturbance whose magnitude was greater than the magnitude of the most severe single contingency." This definition of "excludable disturbance" is entirely consistent with the proposed interpretation. For these reasons, the proposed interpretation of BAL-002 does not constitute a *change* as it is consistent with the historical development of the NERC Reliability Standards.

[21] *See e.g.*, *Amerada Hess Pipeline Corp*., 74 FERC ¶ 61,318, at 62,006 (1996).

E. The Proposed Interpretation of the BAL-002 Reliability Standard is Necessary for Reliability

As NERC noted in its petition for approval, the proposed interpretation of BAL-002 is necessary to prevent Registered Entities from shedding load to avoid possible violations of BAL-002, a result that is inconsistent with reliability principles.

If the BAL-002 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. This was never the intent of the Standard. Registered Entities should not be required to carry excessive Contingency Reserves or otherwise shed load simply for the sake of complying with a Reliability Standard.

F. The Commission Should Defer to NERC's Interpretation of the BAL-002 Reliability Standard Consistent with Section 215 of the Federal Power Act

In Order No. 693, the Commission explained that, through the use of directives, it provides guidance but does not dictate an outcome; rather, it will consider an equivalent alternative approach provided that the ERO demonstrates that the alternative will address the Commission's underlying concern or goal as efficiently and effectively as the Commission's proposal, example or directive. Order No. 693 (at P 31) states:

> We emphasize that we are not, at this time, mandating a particular outcome by way of these directives, but we do expect the ERO to respond with an equivalent alternative and adequate support that fully explains how the alternative produces a result that is as effective as or more effective that [sic] the Commission's example or directive.

The Commission is prohibited from drafting Reliability Standards, including interpretations. This is the responsibility of NERC as the ERO, pursuant to Section 215 of the FPA.[22] The Commission's NOPR therefore accomplishes indirectly that which it is prohibited from doing directly, in contravention of well-established judicial precedent.[23] While the Commission has the authority to remand a proposed NERC interpretation of a Reliability Standard pursuant to Section 215 of the Federal Power Act, a Commission-interpretation of a Reliability Standard would be inconsistent with NERC's ANSI accreditation[24] and the regulatory framework of Section 215. Therefore, where there are two competing interpretations of a Reliability Standard, the NERC interpretation should be entitled to deference where it is technically sound and consistent with reliability principles.

Rather than remanding the interpretation based on a reading of BAL-002 that markedly departs from the intent unambiguously expressed in the words of the interpretation drafting team, demonstrated by the supporting information provided herein, and affirmed by the industry as its long-held understanding, the Commission should approve the interpretation, but also encourage NERC and the industry to move forward expeditiously with revisions to BAL-002 to reduce the potential for future misreadings or differing interpretations.

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[22] 16 U.S.C. § 824o(d)(1).

[23] Courts have consistently held that the Commission cannot do indirectly that which it cannot do directly. *National Fuel Gas Supply Corp. v. FERC*, 909 F.2d 1519, 1522 (D.C. Cir. 1990); *Richmond Power & Light v. FERC*, 574 F.2d 610, 620 (D.C. Cir. 1978).

[24] *See* American National Standards Institute Essential Requirements: Due Process Requirements for American National Standards, Section 3.5, Interpretations Policy: Each ANSI-Accredited Standards Developer shall have on file at ANSI an interpretations policy. Official interpretations of American National Standards shall be made only by the accredited standards developer responsible for maintenance of that standard. ANSI shall not issue, nor shall any person have the authority to issue, an interpretation of an American National Standard in the name of the American National Standards Institute. Requests for interpretations addressed to ANSI shall be referred to the responsible standards developer. *Available at*: http://publicaa.ansi.org/sites/apdl/Documents/Standards%20Activities/American%20National%20Standards/Procedures,%20Guides,%20and%20Forms/2013_ANSI_Essential_Requirements.pdf.

V. <u>Conclusion</u>

For the reasons stated above, NERC respectfully requests that the Commission accept these comments for consideration.

Respectfully submitted,

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July 8, 2013

Attachment A

Mapping Document of NERC Operating Policies to

NERC Version 0 Reliability Standards

Note 1: Statements from Policies and related appendices that have been moved to Version 0 Standards have been highlighted and the new Version 0 location has been identified as: 1.0 moved to Version 0 Standard 001, Requirement 1, (Simplified as 1.0 to 001, R1). Un-highlighted statements have not been included in Version 0 Standards.

Note 2: In the Version 0 standards, policy statements have been changed to "active voice" wording, and entity titles have been changed to reflect the Functional Model. Other wording changes are intended to be clarification of meaning only.

Policy 1 – Generation Control and Performance

Version 2

Policy Subsections

A. Control Performance Standard
B. Disturbance Control Standard
C. Frequency Response and Bias
D. Time Control Standard
E. Automatic Generation Control Standard
F. Inadvertent Interchange Standard
G. Surveys Standard

Introduction

Each CONTROL AREA shall have access to and/or operate resources to provide for a level of OPERATING RESERVE sufficient to account for frequency support, errors in load forecasting, generation loss, transmission unavailability, and regulating requirements. Sufficient OPERATING RESERVES is defined as the capacity required to meet the Control Performance Standard (Section A), Disturbance Control Standard (Section B), and Frequency Response Standard (Section C) of this Policy.

A. Control Performance Standard

[Appendix 1A, "Area Control Error (ACE) Equation"]
["Performance Standard Reference Document"]

Introduction

The CONTROL AREA balance between demand and supply (generation plus INTERCHANGE) is measured by its AREA CONTROL ERROR (ACE). Because supply and demand change unpredictably, there will often be a mismatch between them, resulting in non-zero ACE.

The Control Performance Standard (CPS) establishes the statistical boundaries for ACE magnitudes, ensuring that steady-state frequency is statistically bounded around its scheduled value. Each CONTROL AREA must achieve at least the minimum performance required by the CPS. CPS1 defines the permissible distribution of all CONTROL AREAS' ACEs in an INTERCONNECTION and is based on expected frequency performance within that individual INTERCONNECTION. CPS2 limits the magnitude of the impact that a CONTROL AREA places on its respective INTERCONNECTION. Values controlling the effects of CPS are set by the Resources Subcommittee.

1. **Monitoring.** Each CONTROL AREA shall monitor its control performance against two Standards: CPS1 and CPS2.

(Section 1.1 and included formulae were moved to Version 0 Standard 001 Requirement 1)

Note: for simplicity, identification of new location will be: (1.1 and formulae to 001, R1)

1.1. **Control Performance Standard (CPS1)**. On a rolling 12-month basis, the average of the clock-minute averages of a CONTROL AREA'S ACE divided by 10B (B is the clock-minute average of the CONTROL AREA'S frequency bias) times the corresponding clock-minute averages of the INTERCONNECTION'S FREQUENCY ERROR shall be less than a

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right] \le \epsilon_1^2 \quad or \quad \frac{AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right]}{\epsilon_1^2} \le 1$$

specific limit. This limit ϵ_1^2 is a constant derived from a targeted frequency bound (separately calculated for each INTERCONNECTION) reviewed and set as necessary by the NERC Resources Subcommittee. [See the "**Performance Standard Reference Document"** for application for variable frequency bias.]

(1.2 and formulae moved to 001, R2)

1.2. **Control Performance Standard (CPS2).** The average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month must be within a specific limit, referred to as L_{10}. [See the "**Performance Standard Reference Document**," for the methods for calculating L_{10}.]

$$AVG_{10-\text{minute}}(ACE_i) \le L_{10}$$

where:

$$L_{10} = 1.65\,\epsilon_{10}\sqrt{(-10B_i)(-10B_s)}$$

ϵ_{10} is a constant derived from the targeted frequency bound. It is the targeted RMS of ten-minute average frequency error from schedule based on frequency performance over a given year. The bound, ϵ_{10}, is the same for every control area within an Interconnection.

(2. CPS1 section to 001, Measure M1)

2. **Control Performance Standard (CPS) Compliance.** (CPS1 section to 001, Measure 1) Each CONTROL AREA shall achieve, as a minimum, CPS1 compliance of 100% and (CPS2 section to 001, Measure 2) CPS2 compliance of 90% [See the "**Performance Standard Reference Document," Section C**].

2.1. **CONTROL AREAS Participating in** SUPPLEMENTAL REGULATION SERVICE**.** A CONTROL AREA providing or receiving SUPPLEMENTAL REGULATION SERVICE through DYNAMIC TRANSFER shall continue to be evaluated on the characteristics of its own ACE with the SUPPLEMENTAL REGULATION SERVICE included.

(2.2 to 001, R3)

2.2. **CONTROL AREAS Providing OVERLAP REGULATION SERVICE.** A CONTROL AREA providing OVERLAP REGULATION SERVICE shall evaluate CPS1 and CPS2 using the characteristics of the combined CONTROL AREAS' ACE and combined FREQUENCY BIAS SETTINGS.

(2.3 to 001, R4)

2.3. **CONTROL AREAS Receiving OVERLAP REGULATION SERVICE.** A CONTROL AREA receiving OVERLAP REGULATION SERVICE shall not have its control performance evaluated (i.e. from a control performance perspective, the CONTROL AREA has shifted all control requirements to the CONTROL AREA providing overlap regulation).

B. Disturbance Control Standard

[Appendix 1A – Area Control Error Equation]
[Performance Standard Reference Document]

Introduction

The CONTROL AREA demand-supply balance will quickly change following the sudden loss of load or generation failure. This results in a sudden change in the CONTROL AREA'S ACE, and also a change in INTERCONNECTION frequency. The Disturbance Control Standard measures the CONTROL AREA'S ability to utilize its CONTINGENCY RESERVES 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 the Disturbance Control Standard is limited to the loss of supply and does not apply to the loss of load.

Each CONTROL AREA shall have access to and/or operate resources to provide for a level of CONTINGENCY RESERVE sufficient to meet the DCS performance standards.

(Introductory statement concerning Reserve Sharing Groups has been moved to 001, R1)

RESERVE SHARING GROUPS shall have the same responsibilities and meet the same obligations as individual CONTROL AREAS with regards to monitoring and meeting the Disturbance Control Standard.

Standards

(1. to 002, R1)

1. **CONTINGENCY RESERVES**. Each CONTROL AREA shall have access to and/or operate CONTINGENCY RESERVES to respond to DISTURBANCES. This CONTINGENCY RESERVE is that part of the OPERATING RESERVES that is available, following loss of resources by the CONTROL AREA, to meet the Disturbance Control Standard (DCS). CONTINGENCY RESERVE may be supplied from generation, controllable load resources, or coordinated adjustments to INTERCHANGE SCHEDULES.

(1.1 to 002, R2)

1.1. **CONTINGENCY RESERVE Accounting.** The same portion of RESOURCE CAPACITY shall not be counted by more than one entity (e.g. reserves from jointly owned generation) as part of its CONTINGENCY RESERVES.

(1.2 to 002, R2)

1.2. **REGIONAL CONTINGENCY RESERVE Policies.** Each Region, subregion or RESERVE SHARING GROUP shall specify its CONTINGENCY RESERVE policies, including the minimum reserve requirement for the group, its allocation among members, the permissible mix of OPERATING RESERVE – SPINNING and OPERATING RESERVE – SUPPLEMENTAL that may be included in CONTINGENCY RESERVE, and the procedure for applying CONTINGENCY RESERVE in practice, and the limitations, if any, upon the amount of interruptible load that may be included.

(2. to 002, R3)

2. **CONTINGENCY RESERVE to meet Disturbance Control Standard**. Each CONTROL AREA or RESERVE SHARING GROUP shall activate sufficient CONTINGENCY RESERVE to comply with the

NERC Disturbance Control Standard. As a minimum the CONTROL AREA, or RESERVE SHARING GROUP, shall carry at least enough CONTINGENCY RESERVES to cover the MOST SEVERE SINGLE CONTINGENCY.

(2.1 to 002, R3

2.1. **Contingency review.** All RESERVE SHARING GROUPS and CONTROL AREAS shall at least annually review their probable contingencies to determine their prospective MOST SEVERE SINGLE CONTINGENCIES.

(2.2 to 002, R4)

2.2. **Disturbance Control Standard Compliance.** When a CONTROL AREA or RESERVE SHARING GROUP experiences a REPORTABLE DISTURBANCE (SEE 2.4), it is compliant with the Disturbance Control Standard when the DISTURBANCE RECOVERY CRITERION is met within the DISTURBANCE RECOVERY PERIOD. Each CONTROL AREA or RESERVE SHARING GROUP shall meet the Disturbance Control Standard (DCS) 100% of the time for REPORTABLE DISTURBANCES.

(2.2.1 to 002, R4)

2.2.1. **DISTURBANCE RECOVERY CRITERION.** The CONTROL AREA shall return its ACE to zero if its ACE just prior to the DISTURBANCE was positive or equal to zero. For negative initial ACE values just prior to the DISTURBANCE, the ACE must return to its pre-disturbance value. The default performance criterion described above may be adjusted to better suit the needs of an INTERCONNECTION based on analysis approved by the NERC Resources Subcommittee and the NERC Operating Committee.

(2.2.2 to 002, R4)

2.2.2. **DISTURBANCE RECOVERY PERIOD.** 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 Resources Subcommittee and the NERC Operating Committee.

(2.3 to 002, R5)

2.3. **RESERVE SHARING GROUP.** Each RESERVE SHARING GROUP shall comply with the Disturbance Control Standard. A RESERVE SHARING GROUP shall be considered in a 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 condition but does not call for reserve activation from other members of the RESERVE SHARING GROUP, then that member shall report as a single CONTROL AREA.) Compliance may be demonstrated by either of the following two methods:

(2.3.1 to 002, R5)

2.3.1. **Group compliance to Disturbance Control Standard.** 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.

(2.3.2 to 002, R5)

2.3.2. **Group member compliance to Disturbance Control Standard.** 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. [See Requirement 2.2.2 above.]

(2.4 through 2.5.3 have been moved to 002, Supporting Notes)

2.4. Reportable Disturbances. REPORTABLE DISTURBANCES are contingencies that are greater than or equal to 80% of the MOST SEVERE SINGLE CONTINGENCY loss. Regions 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.

2.5. Treatment of Multiple Contingencies.

2.5.1. 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.

2.5.2. 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 CONTROL AREA 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.

2.5.3. 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 CONTROL AREA 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.

(3. to 002, R6)

3. Restoration of Reserves. Each Control Area must fully restore its CONTINGENCY RESERVES within the CONTINGENCY RESERVE RESTORATION PERIOD for its INTERCONNECTION.

(3.1 to 002, R6)

3.1. Start of CONTINGENCY RESERVE RESTORATION PERIOD. The CONTINGENCY RESERVE RESTORATION PERIOD begins at the end of the DISTURBANCE RECOVERY PERIOD.

(3.2 TO 002, R6)

3.2. CONTINGENCY RESERVE RESTORATION PERIOD. The CONTROL AREA or RESERVE SHARING GROUP shall restore its CONTINGENCY RESERVES within 90 minutes. This period may be adjusted to better suit the reliability targets of the INTERCONNECTION based on analysis approved by the NERC Resources Subcommittee.

(4. to 002, Levels of non compliance)

4. **Disturbance Control Performance Adjustment.** Each CONTROL AREA or RESERVE SHARING GROUP *not meeting the Disturbance Control Standard* during a given calendar quarter shall increase its CONTINGENCY RESERVE obligation for the calendar quarter (offset by one month) following the evaluation by the Region and/or the NERC Resources Subcommittee. [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 Disturbance Control Standard 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. [See the "**Performance Standard Reference Document**," Section C.]

(5. to 002, Levels of non compliance)

5. **Reserve Policy Compliance Documentation.** A representative from each CONTROL AREA or RESERVE SHARING GROUP that was non-compliant in the calendar quarter most recently completed shall provide written documentation verifying that the CONTROL AREA or RESERVE SHARING GROUP will apply the appropriate Disturbance Control 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 CONTROL AREA or RESERVE SHARING GROUP is non-compliant.

C. Frequency Response and Bias

[Appendix 1A – The Area Control Error (ACE) Equation]
[Frequency Response Characteristic Survey Training Document]

Requirements (1. to 003, R1)

1. **Bias setting review.** Each CONTROL AREA shall review its FREQUENCY BIAS SETTINGS by January 1 of each year and recalculate its setting to reflect any change in area frequency response characteristic.

(1.1 to 003, R1)

1.1. Bias setting method. The FREQUENCY BIAS SETTING, and the method used to determine the setting, may be changed whenever any of the factors used to determine the current bias value change.

(1.2 to 003, R1)

1.2. Bias setting reporting. Each CONTROL AREA shall report its FREQUENCY BIAS SETTING, and method for determining that setting, to the Performance Subcommittee.

(1.3 to 003, R1)

1.3. Bias setting verification. Each CONTROL AREA must be able to demonstrate and verify to the Performance Subcommittee that its FREQUENCY BIAS SETTING closely matches or is greater than its system response.

Standards

(Standard 1. to 003, R2)

1. **Tie-line bias.** Each CONTROL AREA shall operate its AGC on tie-line frequency bias, unless such operation is adverse to system or INTERCONNECTION reliability. The Standards for tie-line bias control follow:

(1.1 to 003, R2)

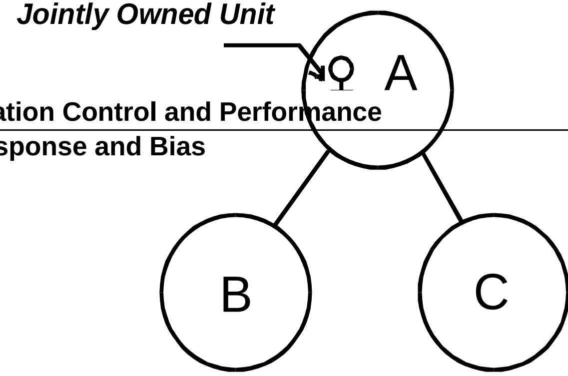
1.1. Bias setting to match frequency response. The CONTROL AREA shall set its frequency bias (expressed in MW/0.1 Hz) as close as practical to the CONTROL AREA's frequency response characteristic. Frequency bias may be calculated several ways:

(1.1.1 to 003, R2)

1.1.1. Fixed bias setting. A fixed frequency bias value may be used which is based on a fixed, straight-line function of tie-line deviation versus frequency deviation. The fixed value shall be determined by observing and averaging the frequency response characteristic for several DISTURBANCES during on-peak hours.

(1.1.2 to 003, R2)

1.1.2. Variable bias setting. A variable (linear or non-linear) bias value may be used which is based on a variable function of tie-line deviation to frequency deviation. The variable frequency bias value shall be determined by analyzing frequency response as it varies with factors such as LOAD, generation, governor characteristics, and frequency.



(1.1.3, and diagram above moved to 003, R3)

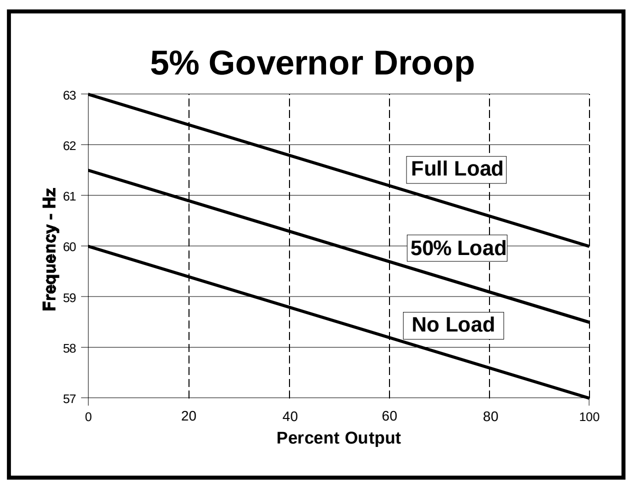
1.1.3. Bias and jointly owned generation. Control Areas that use Dynamic Scheduling or Pseudo-ties for jointly owned units must reflect their respective share of the unit governor droop response into their respective Frequency Bias Setting. Fixed schedules for Jointly Owned Units mandate that the Control Area (A) that contains the Jointly Owned Unit must incorporate the respective share of the unit governor droop response for any Control Areas that have fixed schedules (B and C). The Control Areas that have a fixed schedule (B and C) but do not contain the Jointly Owned Unit should *not* include their share of the governor droop response in their Frequency Bias Setting.

(1.1.4 to 003, R4)

1.1.4. Minimum bias setting for Control Areas that serve native Load. The Control Area's monthly average Frequency Bias Setting must be at least 1% of the Control Area's estimated yearly peak demand per 0.1 Hz change as described in the Frequency Response Characteristic Survey Training Document.

(1.1.5 to 004, R4)

1.1.5. Minimum bias setting for Control Areas that do not serve native Load. The Control Area's monthly average Frequency Bias Setting must be at least 1% of its estimated maximum generation level in the coming year per 0.1 Hz change as described in the Frequency Response Characteristic Survey Training Document.



(1.1.6 to 003, R5)

1.1.6. Bias and overlap regulation. A Control Area that is performing Overlap Regulation Service will increase its Frequency Bias Setting to match the frequency response of the entire area being controlled. A Control Area that is performing Supplemental Regulation Service shall not change its Frequency Bias Setting.

Guides

1. Governor installation. Generating units with nameplate ratings of 10 MW or greater should be equipped with governors operational for frequency response unless restricted by regulatory mandates

2. **Governors free to respond.** Turbine governors and HVDC controls, where applicable, should be allowed to respond to system frequency deviation, unless there is a temporary operating problem.

3. **Governor droop.** All turbine generators equipped with governors should be capable of providing immediate and sustained response to abnormal frequency excursions. Governors should provide a 5% droop characteristic. Governors should, as a minimum, be fully responsive to frequency deviations exceeding ± 0.036 Hz (± 36 mHZ).

4. **Governor limits.** Turbine control systems that provide adjustable limits to governor valve movement (valve position limit or equivalent) should not restrict travel more than necessary to coordinate boiler and turbine response characteristics

Graph showing relation between generator output and Interconnection frequency at 0, 50%, and 100% LOAD for a 5% governor droop characteristic.

D. Time Control Standard

[Appendix 1A — The Area Control Error Equation]
[Appendix 1D — Time Error Correction Procedures]

Introduction

INTERCONNECTION frequency is normally scheduled at 60.00 Hz and controlled to that value. The control is imperfect and over time the frequency will average slightly above or below 60.00 Hz resulting in electric clocks developing an error relative to true time. When the error exceeds pre-set limits, corrective action is taken by adjusting the scheduled frequency, a practice termed Time Error Correction. Each CONTROL AREA shall participate in Interconnection Time Error Correction procedures unless it is operating asynchronously to its INTERCONNECTION.

CONTROL AREAs operating asynchronously may establish their own time error control bands, but must notify the NERC Resources Subcommittee of the bands being utilized, and also provide notification if they are changed.

(To 004, R1)

The Operating Reliability Subcommittee shall designate, on February 1st of each year, a RELIABILITY COORDINATOR to act as the Interconnection Time Monitor to monitor time error for each of the INTERCONNECTIONS and to issue time error correction orders.

Standard

1. **Time error correction notice and commencement.** Time error corrections shall be conducted in accordance with Appendix 1D, "Time Error Correction Procedure."

2. **Time Error Initiation.** Time error corrections will start and end on the hour or half-hour, and notice shall be given at least one hour before the time error correction is to start or stop. All CONTROL AREAS within an INTERCONNECTION shall make all Time Error corrections directed by the Interconnection Time Monitor for its INTERCONNECTION. All CONTROL AREAS within an INTERCONNECTION shall make Time Error Corrections at the same rate.

Requirements

(1. to 004 R2)

1. **Interconnection Time Monitor.** Each Interconnection Time Monitor shall monitor time error and shall initiate or terminate corrective action orders according to the procedure specified in Appendix 1D, "Time Error Correction Procedure."

2. **Time Error Correction labeling.** Time error correction notifications shall be labeled alphabetically on a monthly basis (A-Z, AA-AZ, BA-BZ,…).

(3. to 004, R3)

3. **Time correction offset.** The CONTROL AREA may participate in a Time Error Correction by either of the following two methods:

   1.1. **Frequency offset.** The Control Area may offset its frequency schedule by 0.02 Hz, leaving the FREQUENCY BIAS SETTING normal, or

1.2. **Schedule offset.** If the frequency schedule cannot be offset, the CONTROL AREA may offset its net INTERCHANGE schedule (MW) by an amount equal to the computed bias contribution during a 0.02 Hz frequency deviation (i.e., 20% of the FREQUENCY BIAS SETTING).

(4. to 004 R4)

4. **Request for Termination or Halt of Scheduled Time Error Correction**. Any RELIABILITY COORDINATOR in an INTERCONNECTION may request the termination of a time error correction in progress. Any RELIABILITY COORDINATOR may request the halt of a scheduled time error correction that has not begun. CONTROL AREAs that have reliability concerns with the execution of a time error correction shall notify their RELIABILITY COORDINATOR and request the termination of a time error correction in progress. To enable NERC to track the results of the application of procedures relating to Time Control Standards, a RELIABILITY COORDINATOR requesting a termination or halt of a Time Error Correction shall forward an explanation for requesting the termination to the chairman of the Resources Subcommittee within 5 business days.

5. **INTERCONNECTION time error notification.** The INTERCONNECTION Time Monitor shall on the first day of each month issue a notification of time error, accurate to within 0.01 second, to the other RELIABILITY COORDINATORS within the INTERCONNECTION to assure uniform calibration of time standards.

   5.1. **Western** INTERCONNECTION **time error notification.** Within the Western INTERCONNECTION, the RELIABILITY COORDINATOR designated as the Interconnection Time Monitor shall provide the accumulated time error (accurate to within 0.001 second) to all CONTROL AREAS on a daily basis at 1400 PDT/PST using the WSCCNet. The alphabetic designator shall accompany time error notification if a time error correction is in progress.

6. **Time correction on reconnection.** When one or more CONTROL AREAs have been separated from the INTERCONNECTION, upon reconnection, they shall adjust their time error devices to coincide with the time error of the INTERCONNECTION. A notification of the adjustment to time error shall be passed through Time Notification Channels as soon as possible after reconnection.

7. **Leap seconds.** CONTROL AREAS using time error devices that are not capable of automatically adjusting for leap seconds shall arrange to receive advance notice of the leap second and make the necessary manual adjustment in a manner that will not introduce an improper INTERCHANGE SCHEDULE into their control system.

E. Automatic Generation Control Standard

[Appendix 1A – The Area Control Error (ACE) Equation]
[Performance Standard Reference Document]

Introduction

CONTROL AREAS utilize AUTOMATIC GENERATION CONTROL (AGC) to automatically direct the loading of REGULATING RESERVE. AGC is used to limit the magnitude of AREA CONTROL ERROR (ACE) variations to the CPS bounds. This section contains Standards that apply to the CONTROL AREA AGC needed to calculate ACE and to routinely deploy the REGULATING RESERVE.

(1. to 005, R1)

1. CONTROL AREA components. All load, generation, and transmission operating in an INTERCONNECTION must be included within the metered boundaries of a CONTROL AREA.

2. Resource Requirements

(2.1 to 005, R2)

2.1. Regulating capability. Each CONTROL AREA shall maintain REGULATING RESERVES that can be controlled by AGC to meet the Control Performance Standard (CPS).

2.2. Regulation Service.

(2.2.1 to 005, R3)

2.2.1. Equipment Requirements. A CONTROL AREA providing REGULATION SERVICE shall ensure that adequate metering, communications and control equipment is employed to prevent such service from becoming a burden on the INTERCONNECTION or other CONTROL AREAS.

(2.2.2 to 005, R4)

2.2.2. Failure Notification. A CONTROL AREA providing REGULATION SERVICE shall notify the host CONTROL AREA for whom it is controlling if it is unable to provide the service, as well as any INTERMEDIARY CONTROL AREAS.

(2.2.2 to 005, R5)

2.2.3. Backup. A CONTROL AREA receiving REGULATION SERVICE shall ensure that backup plans are in place to provide replacement REGULATION SERVICE should the supplying CONTROL AREA no longer be able to provide this service.

3. AUTOMATIC GENERATION CONTROL (AGC).

(3.1 TO 005, R6)

3.1. AGC calculation. The CONTROL AREA'S AUTOMATIC GENERATION CONTROL (AGC) shall compare total NET ACTUAL INTERCHANGE to total NET SCHEDULED INTERCHANGE plus frequency bias obligation to determine the CONTROL AREA'S AREA CONTROL ERROR (ACE). Single CONTROL AREAS operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a CONTROL AREA is unable to calculate ACE for more than 30 minutes it shall notify its RELIABILITY COORDINATOR.

(3.2 to 005, R6

3.2. **AGC operation.** CONTROL AREA AGC shall remain in operation unless such operation adversely impacts the reliability of the INTERCONNECTION.

(3.3 to 005, R6)

3.3. **Manual control.** If AGC has become inoperative, the CONTROL AREA shall use manual control to adjust generation to maintain scheduled INTERCHANGE.

4. **Data Requirements.**

(4.1 to 005, R7)

4.1. **Data scan rates for ACE.** The Control Area shall ensure that data-acquisition for and calculation of ACE occur at least every six seconds.

(4.2 to 005, R7)

4.2. **Frequency.** Each CONTROL AREA shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.

4.3. **NET SCHEDULED INTERCHANGE.**[1]

(4.3.1 to 005 R8)

4.3.1. **Inclusion of Schedules.** The CONTROL AREA shall include all INTERCHANGE SCHEDULES with ADJACENT CONTROL AREAS in the calculation of NET SCHEDULED INTERCHANGE for the AREA CONTROL ERROR (ACE) equation.

(4.3.1.1 to 005, R8)

4.3.1.1. CONTROL AREAS with an HVDC link to another CONTROL AREA connected asynchronously to their INTERCONNECTION may choose to omit the INTERCHANGE SCHEDULE related to the HVDC link from the ACE equation if it is modeled as internal generation or load.

4.3.1.2. This standard may not apply to CONTROL AREAS operating asynchronously from their INTERCONNECTION.

(4.3.2 to 005, R9)

4.3.2. **Dynamic Schedules**. The CONTROL AREA shall include all Dynamic Schedules in the calculation of NET SCHEDULED INTERCHANGE for the ACE equation. (See **Appendix 1A, "Area Control Error (ACE) Equation").**

(4.3.3 to 005, R10)

4.3.3. **Interchange Ramps**. SCHEDULED INTERCHANGE values used in ACE shall include the effect of ramp rates, which are identical and agreed to between affected CONTROL AREAS. All such calculations shall conform to specifications in **Policy 3, "Interchange", Section C, "Interchange Schedule Standards."**

4.4. **Actual Net Interchange.**[2]

[1] Interchange is *scheduled* between ADJACENT CONTROL AREAS as explained in the "Interchange Reference Document." ADJACENT CONTROL AREAS may or may not be *physically* adjacent.

[2] Actual Interchange is always measured between PHYSICALLY ADJACENT CONTROL AREAS as explained in the "Interchange Reference Document."

(4.4.1 to 005, R11)

4.4.1. Tie flows. All tie-line flows between ADJACENT CONTROL AREAS shall be included in each CONTROL AREA's ACE calculation.

(4.4.2 to 005, R11)

4.4.2. Tie-line metering. CONTROL AREA tie-line MW metering shall be telemetered to both control centers, and shall emanate from a common, agreed-upon source using common primary metering equipment. MWh data shall be telemetered or reported at the end of each hour.

(4.4.3 to 005, R11)

4.4.3. Data filtering. The power flow and ACE signals that are utilized for calculation of CONTROL AREA performance or that are transmitted for REGULATION SERVICE shall not be filtered prior to transmission except for anti-aliasing filtering of tie lines.

(4.4.4 to 005, R11)

4.4.4. Metering for jointly owned generation. Common metering equipment shall be installed where DYNAMIC SCHEDULES or PSEUDO-TIES are implemented between two or more CONTROL AREAS to deliver the output of JOINTLY OWNED UNITS or to serve remote LOAD.

4.5. Verification of Tie Flows

(4.5.1 to 005, R12)

4.5.1. Hourly verification of tie flows. Each CONTROL AREA shall perform hourly error checks using tie-line MWh meters with common time synchronization to determine the accuracy of its control equipment.

(4.5.2 to 005, R12)

4.5.2. Adjustments for equipment error. The CONTROL AREA shall adjust the component (e.g., tie line meter) of ACE that is in error (if known) or use the interchange meter error (I_{ME}) term of the ACE equation to compensate for any equipment error until repairs can be made.

4.6. Data Recording and Display.

(4.6.1 to 005, R13)

4.6.1. Minimum data recording. The CONTROL AREA shall provide its SYSTEM OPERATORS with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the CONTROL AREA must provide its SYSTEM OPERATORS with real-time values for AREA CONTROL ERROR (ACE), INTERCONNECTION frequency and NET ACTUAL INTERCHANGE with each ADJACENT CONTROL AREA.

(4.6.2 TO 005, R13)

4.6.2. Backup power for data recording. The CONTROL AREA shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the CONTROL AREA'S control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.

4.7. Data Quality. The CONTROL AREA shall ensure data quality:

(4.7.1 to 005, R14)

4.7.1. Data Integrity. Data shall be sampled at least at the same periodicity with which ACE is calculated.

(4.7.2 to 005, R14)

4.7.2. Missing or bad data. Missing or bad data shall be flagged for operator display and archival purposes.

(4.7.3 to 005, R14)

4.7.3. Coincident Data Sampling. Collected data shall be coincident to the greatest practical extent; i.e., ACE, INTERCONNECTION frequency, net interchange, and other data (see section 4.8.1) shall all be sampled at the same time.

(4.7.4 and the list, to 005, R14)

4.7.4. Data Accuracy. Control performance and reliable operation is affected by the accuracy of the measuring devices. The required minimum values for measuring devices are listed below:

Device	***Accuracy***	***Units***
Digital frequency transducer	≤ 0.001	Hz
MW, MVAR, and voltage transducer	≤ 0.25	% of full scale
Remote terminal unit	≤ 0.25	
Potential transformer	≤ 0.30	
Current transformer	≤ 0.50	

4.8. Data Retention.

(4.8.1 to 005, Compliance Monitoring Process)

4.8.1. Performance Standard Data. Each CONTROL AREA shall retain its ACE, actual frequency, SCHEDULED FREQUENCY, NET ACTUAL INTERCHANGE, NET SCHEDULED INTERCHANGE, tie-line meter error correction and FREQUENCY BIAS SETTING data in digital format at the same scan rate at which the data is collected for at least one year.

(4.8.2 to 005, Compliance Monitoring Process)

4.8.2. Disturbance Control Performance Data. Each CONTROL AREA or RESERVE SHARING GROUP shall retain documentation of the magnitude of each REPORTABLE DISTURBANCE as well as the ACE charts and/or samples used to calculate the CONTROL AREA'S or RESERVE SHARING GROUP'S disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

(4.8.3 to 005, Compliance Monitoring Process)

4.8.3. **Data Format**. CONTROL AREAs shall be prepared to supply data to NERC in the industry standard format (defined below):

(4.8.3.1 to 005, Compliance Monitoring Process)

4.8.3.1. CPS source data in daily CSV files with time stamped one minute averages of: 1) ACE and 2) Frequency Deviation from Schedule, will be provided to NERC or the Regions within one week upon request.

(4.8.3.2 to 005, Compliance Monitoring Process)

4.8.3.2. DCS source data will be supplied in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Deviation from Schedule for a time period, from two minute prior to thirty minutes after the identified disturbance, will be provided to NERC or the Regions within one week upon request.

4.8.3.3. Other data (as defined in **Requirement 4.8.1, "Performance Standard Data"**) may be requested on an ad hoc basis by NERC and the Regions.

4.8.3.4. A sample of the specific file format and naming convention required can be found on the NERC Resources Subcommittee web page.

(5. to 005, R15)

5. **Calibration of measurement devices.** Each CONTROL AREA shall at least annually check and calibrate its time error and frequency devices against a common reference.

F. Inadvertent Interchange Standard

[Appendix 1F, "Inadvertent Interchange Dispute Resolution Process and Error Adjustment Procedures"]
["Inadvertent Interchange Accounting Training Document"]
[Policy 3, "Introduction"]

Introduction

INADVERTENT INTERCHANGE provides a measure of non-scheduled INTERCHANGE and bilaterally scheduled inadvertent payback. These transfers are caused by such factors as CONTROL AREA regulation and frequency response, metering errors in frequency and/or interchange measurements (either scheduled or actual), unilateral INADVERTENT INTERCHANGE payback and human errors.

The INADVERTENT INTERCHANGE Standard defines a process for monitoring CONTROL AREAS to help ensure that, over the long term, the CONTROL AREAS do not excessively depend on other CONTROL AREAS in the INTERCONNECTION for meeting their demand or INTERCHANGE obligations.

Each CONTROL AREA shall, through daily INTERCHANGE SCHEDULE verification and the use of reliable metering equipment, accurately account for INADVERTENT INTERCHANGE. Each CONTROL AREA shall actively prevent unintentional INADVERTENT INTERCHANGE accumulation due to poor control. Each CONTROL AREA shall also be diligent in reducing accumulated inadvertent balances in accordance with Operating Policies.

Standards

(Standard 1. to 006, R1)

1. **INADVERTENT INTERCHANGE calculation.** INADVERTENT INTERCHANGE shall be calculated and recorded hourly. INADVERTENT INTERCHANGE may accumulate as energy into or out of the CONTROL AREA.

(Standard 2. to 006, R2)

2. **Including all interconnections.** Each CONTROL AREA shall include all AC tie lines that connect to its physically ADJACENT CONTROL AREAS in its INADVERTENT INTERCHANGE account. Interchange served through jointly owned facilities must be properly taken into account.

(Standard 3. to 006, R3)

3. **Metering requirements.** All CONTROL AREA INTERCONNECTION points shall be equipped with common MWh meters, with readings provided hourly to the control centers of both ADJACENT CONTROL AREAS.

(Standard 4. to 006, R4)

4. **INADVERTENT INTERCHANGE Accounting.** ADJACENT CONTROL AREAS shall operate to a common NET INTERCHANGE SCHEDULE and ACTUAL NET INTERCHANGE value and shall record these hourly quantities, with like values but opposite sign. Each CONTROL AREA shall compute its INADVERTENT INTERCHANGE based on the following:

(4.1 to 006, R4)

4.1. Daily accounting. Each CONTROL AREA, by the end of the next business day, shall agree with its adjacent CONTROL AREAS to:

(4.1.1 to 006, R4)

4.1.1. The hourly values of NET INTERCHANGE SCHEDULE.

(4.1.2 to 006, R4)

4.1.2. The hourly integrated MWh values of NET ACTUAL INTERCHANGE

(4.2 TO 006, R4)

4.2. Monthly accounting. Each CONTROL AREA shall use the agreed-to Daily and Monthly accounting data to compile its monthly accumulated INADVERTENT INTERCHANGE for the On-Peak and Off-Peak hours of the month. **[Refer to "Inadvertent Interchange Accounting Training Document"]**

(4.3 to 006, R4)

4.3. After-the-Fact Corrections. After-the-fact corrections to the agreed-to Daily and Monthly accounting data shall only be made to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the CONTROL AREA's INADVERTENT INTERCHANGE. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the ADJACENT CONTROL AREA(s).

5. INADVERTENT INTERCHANGE payback. Each CONTROL AREA shall be diligent in reducing accumulated inadvertent balances. INADVERTENT INTERCHANGE accumulations shall be paid back by either of the following methods:

5.1. Energy "in-kind" payback. INADVERTENT INTERCHANGE accumulated during "on-peak" hours shall only be paid back during "on-peak" hours. INADVERTENT INTERCHANGE accumulated during "off-peak" hours shall only be paid back during "off-peak" hours. [**See Appendix 1F, "On-Peak and Off-Peak Periods."**]

5.1.1. Bilateral payback. INADVERTENT INTERCHANGE accumulations may be paid back via an INTERCHANGE SCHEDULE with another CONTROL AREA. **[Refer to Policy 3, "Interchange" for Interchange Scheduling Requirements.]**

5.1.1.1. Opposite balances. The SOURCE CONTROL AREA and SINK CONTROL AREA must have inadvertent accumulations in the opposite direction.

5.1.1.2. Agreement on schedule. The terms of the inadvertent payback INTERCHANGE SCHEDULE shall be agreed upon by all involved CONTROL AREAS and TRANSMISSION PROVIDERS in accordance with NERC operating **Policy 3, "Interchange."**

5.1.2. Unilateral payback. INADVERTENT INTERCHANGE accumulations may be paid back unilaterally controlling to a target of non-zero ACE. Controlling to a non-zero ACE ensures that the unilateral payback is accounted for in the CPS calculations. The unilateral payback control offset is limited to the CONTROL AREA's L_{10} limit and shall not burden the INTERCONNECTION.

5.2. **Other payback methods.** Upon agreement by all REGIONS within an INTERCONNECTION, other methods of INADVERTENT INTERCHANGE payback may be utilized.

(6. to 006, Compliance Monitoring Process)

6. **INADVERTENT INTERCHANGE summary.** Each CONTROL AREA shall submit a monthly summary of INADVERTENT INTERCHANGE as detailed in **Appendix 1F,** "Inadvertent Interchange **Energy Accounting Practices and Dispute Resolution Process."** These summaries shall not include any after-the-fact changes that were not agreed to by the SOURCE CONTROL AREA, SINK CONTROL AREA and all INTERMEDIARY CONTROL AREA(s).

(6.1 to 006, Compliance Monitoring Process)

6.1. **Summary balances.** INADVERTENT INTERCHANGE summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both the "on-peak" and "off-peak" periods.

(6.2 to 006, Compliance Monitoring Process)

6.2. **Summary submission.** Each CONTROL AREA shall submit its monthly summary report to its Resources Subcommittee Survey Contact by the 15th calendar day of the following month. The Resources Subcommittee Survey Contact will prepare a composite tabulation and submit that tabulation to the NERC staff by the 22nd calendar day of the month.

(6.2.1 to 006, Levels of Non Compliance)

6.2.1. **Failure to Report.** A CONTROL AREA that neither submits a report nor supplies a reason for not submitting the required data by the 20th calendar day of the following month shall be considered non-compliant.

(6.2.2 to 006, R5)

6.2.2. **Dispute Resolution.** Adjacent CONTROL AREAS that cannot mutually agree upon their respective NET ACTUAL INTERCHANGE or NET SCHEDULED INTERCHANGE quantities by the 15th calendar day of the following month shall, for the purposes of dispute resolution, submit a report to their respective Resources Subcommittee Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy. The Dispute Resolution Process is described in **Appendix 1F, "Inadvertent Interchange Dispute Resolution Process and Error Adjustment Procedures."**

G. Surveys Standard

[Area Interchange Error Survey Training Document]
[Frequency Response Characteristic Survey Training Document]
[Performance Standard Reference Document]

Introduction

Periodic surveys of the control performance of the CONTROL AREAS are conducted to reveal control equipment malfunctions, telemetering errors, improper frequency bias settings, scheduling errors, inadequate generation under automatic control, general control performance deficiencies, or other factors contributing to inadequate control performance.

Requirements

(1. and 1.1 to 006, Compliance Monitoring Process)

1. **On-request Surveys.** Each CONTROL AREA shall perform each of the following surveys, as described in the Performance Standard Reference Document, when called for by the Resources Subcommittee:

   1.1. **AIE survey.** Area Interchange Error survey to determine the CONTROL AREAS' INTERCHANGE error(s) due to equipment failures or improper SCHEDULING operations, or improper AGC performance.

   1.2. **FRC survey.** Frequency Response Characteristic survey to determine the CONTROL AREAS' response to INTERCONNECTION FREQUENCY DEVIATIONS.

2. **Ongoing Surveys.** Each CONTROL AREA shall submit the following surveys on a regular basis as specified below:

   2.1. **CPS, DCS, and FRS Surveys.** Performance Standard surveys to monitor the CONTROL AREAS' control performance during normal and DISTURBANCE situations.

   2.1.1. **CPS Surveys.** Each CONTROL AREA shall submit a CPS Survey to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the month. The Resources Subcommittee Survey Contact shall submit the CPS survey to NERC no later than the 20th day following the end of the month.

   2.1.2. **DCS Surveys.** Each CONTROL AREA 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 Resources Subcommittee Survey Contact shall submit the CPS survey to NERC no later than the 20th day following the end of the calendar quarter.

   2.1.3. **FRS Surveys.** Each CONTROL AREA or RESERVE SHARING GROUP shall submit one completed copy of FRS Form, "NERC Frequency Response Standard Survey – All Interconnections" to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the calendar month in which the survey was called. The Resources Subcommittee Survey Contact shall submit the FRS survey to NERC no later than the

Section 2.1.3 is contingent upon approval of Section C, Version 2.

20th day of that same month.

(2.2 to 006, Compliance Monitoring Process)

2.2. **Inadvertent Interchange Summaries (surveys).** Each Region shall prepare an Inadvertent Interchange summary monthly to monitor the CONTROL AREAs' monthly Inadvertent Interchange and all-time accumulated Inadvertent Interchange. Each Region shall submit a monthly accounting to NERC by the 22nd day following the end of the month being summarized.

Note 1: Statements from Policies and related appendices that have been moved to Version 0 Standards have been highlighted and the new Version 0 location has been identified as: 1.0 moved to Version 0 Standard 001, Requirement 1, (Simplified as 1.0 to 001, R1). Un-highlighted statements have not been included in Version 0 Standards.
Note 2: In the Version 0 standards, policy statements have been changed to "active voice" wording, and entity titles have been changed to reflect the Functional Model. Other wording changes are intended to be clarification of meaning only.

Policy 2 — Transmission

Policy Subsections

A. Transmission Operations
B. Voltage and Reactive Control

Introduction

This Policy specifies the requirements for operating the transmission system to maintain transmission security. These requirements include transmission operation, (The requirement for establishing Reliability Coordinators has been moved to 033, R2) establishment of one or more RELIABILITY COORDINATORS, and voltage and reactive control.

A. Transmission Operations

[Policy 4B – System Coordination – Operational Security Information]
[Policy 5C – Transmission System Relief]

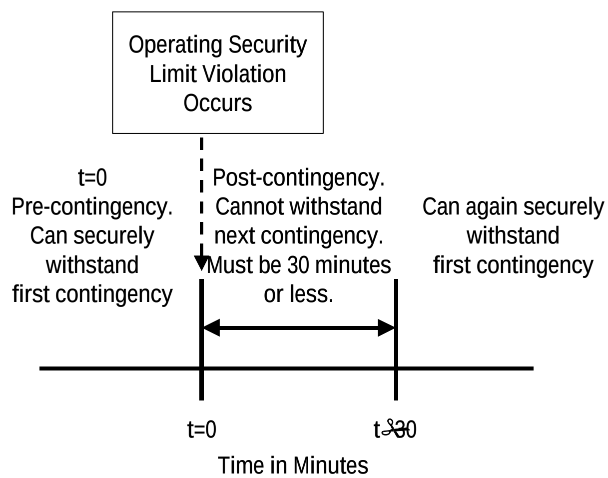
Standards

(1. to 007, R2)

1. Basic reliability requirement regarding single contingencies. All CONTROL AREAS shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.

(1.1 to 007, R3)

1.1. Multiple outages. Multiple outages of a credible nature, as specified by Regional policy, shall also be examined and, when practical, the CONTROL AREAS shall operate to protect against instability, uncontrolled separation, or cascading outages resulting from these multiple outages.



1.2. OPERATING SECURITY LIMITS. OPERATING SECURITY LIMITS define the acceptable operating boundaries.

(2. TO 008, R2)

2. **Return from OPERATING SECURITY LIMIT Violation.** Following a contingency or other event that results in an OPERATING SECURITY LIMIT violation, the CONTROL AREA shall return its transmission system to within OPERATING SECURITY LIMITS soon as possible, but no longer than 30 minutes.

(2.1 to 008, R5)

2.1. **Reporting Non-compliance**. Each violation of this Standard shall be reported to the Regional Council and NERC Compliance Subcommittee within 72 hours.

2.2. **Reporting format.** The report will be submitted on the NERC Preliminary Disturbance Report Form as found in Appendix 5F, "Reporting Requirements for Major Electric System Emergencies**.**

Requirements

(Requirement 1. to 007, R6)

1. **Policies for dealing with transmission security.** CONTROL AREAS, individually and jointly, shall develop, maintain, and implement formal policies and procedures to provide for transmission security. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional security, including:

   - Equipment ratings
   - Monitoring and controlling voltage levels and real and reactive power flows
   - Switching transmission elements
   - Planned outages of transmission elements
   - Development of Operating Security Limits
   - Responding to OPERATING SECURITY LIMIT violations.

   1.1. Responsibility for transmission security. When OPERATING SECURITY LIMIT violations occur, or are expected to occur, the CONTROL AREAS affected by and the CONTROL AREAS contributing to these violations shall implement established joint actions to restore transmission security.

   (1.2 to 008, R3)

   1.2. Action to keep transmission within limits. CONTROL AREAS shall take all appropriate action up to and including shedding of firm load in order to comply with Standard 2.A.2.

   (2. to 033, R2)

2. **Reliability Coordination.** Every Region, subregion, or interregional coordinating group shall establish one or more RELIABILITY COORDINATORS to continuously assess transmission security and coordinate emergency operations among the CONTROL AREAS within the Subregion, Region, and across the Regional boundaries.

   2.1. TRANSMISSION OPERATING ENTITIES shall cooperate with their HOST CONTROL AREAS to ensure their operations support the reliability of the INTERCONNECTION.

   (3. Covered under policy 4 Standards)

3. **Coordinating transmission outages.** Planned transmission outages shall be coordinated with any system that operations planning studies show might be affected.

B. Voltage and Reactive Control

Requirements

(1. to 009, R1)

1. **Monitoring and controlling voltage and MVAR flows.** Each CONTROL AREA, individually and jointly, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and MVAR flows within its boundaries and with neighboring CONTROL AREAS.

(2. to 009, R2)

2. **Providing reactive resources.** Each CONTROL AREA shall supply reactive resources within its boundaries to protect the voltage levels under contingency conditions. This includes the CONTROL AREA'S share of the reactive requirements of interconnecting transmission circuits.

   (2.1 to 009, R3)

   2.1. **Providing for reactive requirements.** Each PURCHASING-SELLING ENTITY shall arrange for (self-provide or purchase) reactive resources for its reactive requirements.

(3. to 009, R4)

3. **Operating reactive resources.** Each CONTROL AREA shall operate their capacitive and inductive reactive resources to maintain system and INTERCONNECTION voltages within established limits.

   (3.1 to 009, R5)

   3.1. **Actions.** Reactive generation scheduling, transmission line and reactive resource switching, etc., and load shedding, if necessary, shall be implemented to maintain these voltage levels.

   (3.2 to 009, R6)

   3.2. **Reactive resources.** Each CONTROL AREA shall maintain reactive resources to support its voltage under first contingency conditions.

   (3.2.1 to 009, R6)

      3.2.1. **Location.** Reactive resources shall be dispersed and located electrically so that they can be applied effectively and quickly when contingencies occur.

   (3.2.2 to 009, R7)

      3.2.2. **Reactive restoration.** Security Limit Violations resulting from reactive resource deficiencies shall be corrected in accordance with Standard 2.A.1. and 2.A.2.

   (3.3 to 009, R8)

   3.3. **Field excitation for stability.** When a generator's voltage regulator is out of service, field excitation shall be maintained at a level to maintain Interconnection and generator stability.

(4. to 009, R8 specifically relating to Generator Operators)

(4. Repeated in 009, R9 specifically relating to Transmission Operators)

4. **Operator information.** The SYSTEM OPERATOR shall be provided information on all available generation and transmission reactive power resources, including the status of voltage regulators and power system stabilizers.

(5. to 009, R10)

5. **Preventing Voltage Collapse.** The SYSTEM OPERATOR shall take corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

(6. to 009, R11)

6. **Voltage and reactive devices.** Devices used to regulate transmission voltage and reactive flow shall be available under the direction of the SYSTEM OPERATOR.

(Guides – moved to 009 Standard as an attachment)

Guides

1. **Keeping lines in service.** Transmission lines should be kept in service as much as possible. They may be removed from service for voltage control only after studies indicate that system reliability will not be degraded below acceptable levels.

2. **Keeping voltage and reactive control devices in service.** Devices used to regulate transmission voltage and reactive flow, including automatic voltage regulators and power system stabilizers on generators and synchronous condensers, should be kept in service as much of the time as possible.

3. **Voltage and reactive devices.** Devices used to regulate transmission voltage and reactive flow should be switchable without de-energizing other facilities.

4. **DC equipment.** Systems with dc transmission facilities should utilize reactive capabilities of converter terminal equipment for voltage control.

5. **Reactive capability testing.** Generating units and other dynamic reactive resources should be tested periodically to determine achievable reactive capability limits.

Note 1: Statements from Policies and related appendices that have been moved to Version 0 Standards have been highlighted and the new Version 0 location has been identified as: 1.0 moved to Version 0 Standard 001, Requirement 1, (Simplified as 1.0 to 001, R1). Un-highlighted statements have not been included in Version 0 Standards.
Note 2: In the Version 0 standards, policy statements have been changed to "active voice" wording, and entity titles have been changed to reflect the Functional Model. Other wording changes are intended to be clarification of meaning only.

Policy 3 – Interchange

Version 5.2

[See also, "Interchange Reference Document"]

Policy Subsections

A. Interchange Transaction Implementation
B. Interchange Schedule Implementation
C. Interchange Schedule Standards
D. Interchange Transaction Modifications

Introduction

This Policy addresses the following issues:

- Responsibilities of all PURCHASING-SELLING ENTITIES involved in INTERCHANGE TRANSACTIONS. [1]
- Information requirements for INTERCHANGE TRANSACTIONS.
- Requirements of CONTROL AREAS to assess and confirm INTERCHANGE TRANSACTIONS.
- Accountability of CONTROL AREAS for implementing all INTERCHANGE SCHEDULES in a manner that ensures the reliability of the INTERCONNECTIONS.
- Standards for INTERCHANGE SCHEDULES between CONTROL AREAS.
- Requirements for INTERCHANGE TRANSACTION Cancellation, Termination, and Curtailment.

[1] This Policy deals predominately with INTERCHANGE TRANSACTIONS, that is, those that cross one or more CONTROL AREA boundaries. The more general term "TRANSACTION" includes INTERCHANGE TRANSACTIONS and TRANSACTIONS that are entirely within a CONTROL AREA. At this time, the only reference to the general term "TRANSACTION" is the tagging requirement in Requirement 3.A.2.1.

A. Interchange Transaction Implementation

[Policy 2A, "Transmission—Transmission Operations"]
[Appendix 3A1, "Tag Submission and Response Timetables"]
[Appendix 3A2, "Tagging Across Interconnection Boundaries]
["E-Tag Spec"]
["Transaction Tagging Process within ERCOT Reference Document"]

Introduction

This section specifies the PURCHASING-SELLING ENTITY'S requirements for tagging all INTERCHANGE TRANSACTIONS, the CONTROL AREAS' and TRANSMISSION PROVIDERS' obligations for accepting the tags, and CONTROL AREAS' obligations for implementing the INTERCHANGE TRANSACTIONS. The tag data is integral for providing the CONTROL AREAS, RELIABILITY COORDINATORS, and other operating entities the information they need to assess, confirm, approve or deny, implement, and curtail INTERCHANGE TRANSACTIONS as necessary to accommodate the marketplace and ensure the operational security of the INTERCONNECTION.

Requirements

1. **INTERCHANGE TRANSACTION arrangements.** The PURCHASING-SELLING ENTITY shall arrange for all Transmission Services, tagging, and contact personnel for each INTERCHANGE TRANSACTION to which it is a party.

   1.1. Transmission services. The PURCHASING-SELLING ENTITY shall arrange the Transmission Services necessary for the receipt, transfer, and delivery of the TRANSACTION.

   (First and last sentence to 010, R1)

   1.2. Tagging. The PURCHASING-SELLING ENTITY serving the load shall be responsible for providing the INTERCHANGE TRANSACTION tag.

   (Note in the middle to 010, R4) (Note: 1. Any PSE may provide the tag; however, the load-serving PSE is responsible for ensuring that a single tag is provided. 2. If a PSE is not involved in the TRANSACTION, such as delivery from a jointly owned generator, then the SINK CONTROL AREA is responsible for providing the tag.)

   PSEs must provide tags for all INTERCHANGE TRANSACTIONS in accordance with Requirement 2.)

   1.3. Contact personnel. Each PURCHASING-SELLING ENTITY with title to an INTERCHANGE TRANSACTION must have, or arrange to have, personnel directly and immediately available for notification of INTERCHANGE TRANSACTION changes. These personnel shall be available from the time that title to the INTERCHANGE TRANSACTION is acquired until the INTERCHANGE TRANSACTION has been completed.

   1.4. E-Tag monitoring. CONTROL AREAS, TRANSMISSION PROVIDERS, and PURCHASING-SELLING ENTITIES who are responsible for a tagged TRANSACTION shall have facilities to receive unsolicited notification from the Tag Authority of changes in the status of a tag with which the user is a participant.

2. **INTERCHANGE TRANSACTION tagging.** Each INTERCHANGE TRANSACTION shall be tagged before implementation as required by each INTERCONNECTION as specified in the **"E-Tag Spec" or "Transaction Tagging Process within ERCOT Reference Document."** In addition to providing necessary operating information, the INTERCHANGE TRANSACTION tag is the official

request from the PURCHASING-SELLING ENTITY to the CONTROL AREAS to implement the INTERCHANGE TRANSACTION. The information that must be provided on the tag is listed in **Appendix 3A4**.

2.1. **Application to TRANSACTIONS.** All INTERCHANGE TRANSACTIONS and certain INTERCHANGE SCHEDULES shall be tagged. In addition, intra-CONTROL AREA transfers using Point-to-Point Transmission Service[2] shall be tagged. This includes:

- INTERCHANGE TRANSACTIONS (those that are between CONTROL AREAS).
- TRANSACTIONS that are entirely within a CONTROL AREA.
- DYNAMIC INTERCHANGE SCHEDULES (tagged at the expected average MW profile for each hour). (Note: a change in the hourly energy profile of 25% or more requires a revised tag.)

(The following bullet is included in 010, R3)

- INTERCHANGE TRANSACTIONS for bilateral INADVERTENT INTERCHANGE payback (tagged by the SINK CONTROL AREA).

(The following bullet is included in 010, R2)

- INTERCHANGE TRANSACTIONS established to replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements, are exempt from tagging for 60 minutes from the time at which the INTERCHANGE TRANSACTION begins (tagged by the SINK CONTROL AREA). **[See also, Policy 1E2 and 2.1, "Disturbance Control Standard"]**

(2.2 TO 011, R1)

2.2. **Parties to whom the complete tag is provided.** The tag, including all updates and notifications, shall be provided to the following entities:

- Generation Providing Entity
- Generation CONTROL AREA
- TRANSMISSION PROVIDERS
- Transmission Customers
- SCHEDULING ENTITIES
- Intermediate PURCHASING-SELLING ENTITIES (Title-Holders)
- Load CONTROL AREA
- LOAD-SERVING ENTITY
- Market Redispatch Notification Entities (if specified)
- Security Analysis Services

2.3. **Method of transmitting the tag.** The PURCHASING-SELLING ENTITY shall submit the INTERCHANGE TRANSACTION tag in the format established by each INTERCONNECTION. **["E-Tag Spec" or "Transaction Tagging Process within ERCOT Reference Document"]**

[2] This includes all "grandfathered" and other "non-888" Point-to-Point Transmission Service

2.3.1. **Tags for INTERCHANGE TRANSACTIONS that cross INTERCONNECTION boundaries.** Procedures are found in **Appendix 3A2, "Tagging Across Interconnection Boundaries."**

(2.4 to 010, R5)

2.4. **INTERCHANGE TRANSACTION submission time.** To provide adequate time for INTERCHANGE SCHEDULE implementation, INTERCHANGE TRANSACTIONS shall be submitted as specified in **Appendix 3A1, "Tag Submission and Response Timetable."**

2.4.1. **Exception for security reasons**. Exception to the submission time requirements in Section 2.4 is allowed if immediate changes to the INTERCHANGE TRANSACTIONS are required to mitigate an OPERATING SECURITY LIMIT violation. The tag may be submitted after the emergency TRANSACTION has been implemented but no later than 60 minutes.

2.5. **Confirmation of tag receipt.** Confirmation of tag receipt shall be provided to the PURCHASING-SELLING ENTITY who submitted the tag in accordance with INTERCONNECTION tagging practices. **["E-Tag Spec"]**

2.6. **Tag acceptance.** An INTERCHANGE TRANSACTION tag shall be accepted if all required information is valid and provided in accordance with the tagging specifications in Requirement 2.

3. **INTERCHANGE TRANSACTION tag receipt verification.** The SINK CONTROL AREA shall verify the receipt of each INTERCHANGE TRANSACTION tag with the TRANSMISSION PROVIDERS, and CONTROL AREAS on the SCHEDULING PATH before the INTERCHANGE TRANSACTION is implemented.

4. **INTERCHANGE TRANSACTION assessment**. (This section to 011, R2) GENERATION PROVIDING ENTITIES, LOAD SERVING ENTITIES, TRANSMISSION PROVIDERS, CONTROL AREAS on the SCHEDULING PATH, and other operating entities responsible for operational security shall be responsible for assessing and "approving" or "denying" INTERCHANGE TRANSACTIONS as requested by PURCHASING-SELLING ENTITIES, based on established reliability criteria and adequacy of INTERCONNECTED OPERATIONS SERVICES and transmission rights as well as the reasonableness of the INTERCHANGE TRANSACTION tag.

NERC expects that Approval Entities have the proper resources to perform these assessments. Lack of these tools is not a reason to deny an Interchange Transaction. Resources include personnel and tools.

(THIS SECTION TO 011, R3)GENERATION PROVIDING ENTITIES and LOAD SERVING ENTITIES may elect to defer their approval responsibility to their HOST CONTROL AREA.

This assessment shall include the following:

The CONTROL AREA assesses:

- (TO 011, R3) TRANSACTION start and end time
- (TO 011, R3) ENERGY PROFILE (ABILITY OF GENERATION MANEUVERABILITY TO ACCOMMODATE)
- (TO 011, R3) SCHEDULING PATH (proper connectivity of ADJACENT CONTROL AREAS)

The TRANSMISSION PROVIDER assesses:

- (To 011, R2) Valid OASIS reservation number or transmission contract identifier
- (To 011, R2) Proper transmission priority
- (To 011, R2) Energy profile accommodation (does energy profile fit OASIS reservation?)
- (To 011, R2) OASIS reservation accommodation of all INTERCHANGE TRANSACTIONS
- (To 011, R2) Loss accounting

The GENERATION PROVIDING ENTITY and LOAD-SERVING ENTITY assess:

- Transaction is valid representation of contractually agreed upon energy delivery

4.1. **Tag corrections**. During the CONTROL AREAS' and TRANSMISSION PROVIDERS' assessment time, the PURCHASING-SELLING ENTITY who submitted the tag may elect to submit a tag correction. Tag corrections are changes to an existing tag that do not affect the reliability impacts of the INTERCHANGE TRANSACTION; therefore, tag corrections do not require the complete re-assessment of the tag by all CONTROL AREAS and TRANSMISSION PROVIDERS on the SCHEDULING PATH, or the completion and submission of a new tag by the PURCHASING-SELLING ENTITY. The SINK CONTROL AREA shall notify all CONTROL AREAS and TRANSMISSION PROVIDERS on the SCHEDULING PATH of the correction, and specifically alert those entities for which a correction has impact. Entities who are impacted by the correction will have an opportunity to reevaluate the tag status. The timing requirements for corrections are found in **Appendix 3A1, "Tag Submission and Response Timetable**." Tag items that may be corrected are found in **Appendix 3A4, "Required Tag Data."** A description of those entities who may correct an INTERCHANGE TRANSACTION tag is found in **Appendix 3D, "Transaction Tag Actions." [See Appendix 3A1 Subsection C, Interchange Transaction Corrections.]**

5. **INTERCHANGE TRANSACTION approval or denial.** (To 011, R4) Each CONTROL AREA or TRANSMISSION PROVIDER on the SCHEDULING PATH responsible for assessing and "approving" or "denying" the INTERCHANGE TRANSACTION shall notify the SINK CONTROL AREA.

(To 011, R5) The SINK CONTROL AREA in turn notifies the PURCHASING-SELLING ENTITY who submitted the INTERCHANGE TRANSACTION tag, plus all other CONTROL AREAS and TRANSMISSION PROVIDERS on the SCHEDULING PATH.

Assessment timing requirements are found in **Appendix 3A1, "Tag Submission and Response Timetable."** A description of those entities who may approve or deny an INTERCHANGE TRANSACTION is found in **Appendix 3D, "Transaction Tag Actions."**

5.1. **INTERCHANGE TRANSACTION denial.** If denied, this notification shall include the reason for the denial.

5.2. **INTERCHANGE TRANSACTION approval.** The INTERCHANGE TRANSACTION is considered approved if the PURCHASING-SELLING ENTITY who submitted the INTERCHANGE TRANSACTION tag has received confirmation of tag receipt and has not been notified that the transaction is denied.

(6. TO 012, R3)

6. **Responsibility for INTERCHANGE TRANSACTION implementation.** The SINK CONTROL AREA is responsible for initiating the implementation of each INTERCHANGE TRANSACTION as tagged in accordance with Policy 3.A. Requirement 2 (and its subparts). The INTERCHANGE TRANSACTION is incorporated into the INTERCHANGE SCHEDULE(S) of all CONTROL AREAS on the SCHEDULING PATH in accordance with Policy 3B.

6.1. **Tag requirements for INTERCHANGE TRANSACTION implementation.** The CONTROL AREA shall implement only those INTERCHANGE TRANSACTIONS that:

- Have been tagged in accordance with Requirement 2 above, or,
- Are exempt from tagging in accordance with Requirement 2.1 above.

7. **Tag requirements after curtailment has ended.** After the curtailment of a TRANSACTION has ended, the INTERCHANGE TRANSACTION'S energy profile will return to the originally requested level unless otherwise specified by the PURCHASING-SELLING ENTITY. [See **Interchange Transaction Reallocation During TLR Levels 3a and 5a Reference Document, Version 1 Draft 6.**]

8. **Confidentiality of information.** RELIABILITY COORDINATORS, CONTROL AREAS, TRANSMISSION PROVIDERS, PURCHASING-SELLING ENTITIES, and entities serving as tag agents or service providers as provided in the **"E-Tag Spec"** shall not disclose INTERCHANGE TRANSACTION information to any PURCHASING-SELLING ENTITY except as provided for in Requirement 2.2 above, "**Parties to whom the complete tag is provided.**"

B. Interchange Schedule Implementation

[Policy 2A, "Transmission—Transmission Operations"]

Introduction

This section explains CONTROL AREA requirements for implementing the INTERCHANGE SCHEDULES that result from the INTERCHANGE TRANSACTIONS tagged by the PURCHASING-SELLING ENTITIES in Section A.

Requirements

(1. to 012, R2)

1. **CONTROL AREAS must be adjacent.** INTERCHANGE SCHEDULES shall only be implemented between ADJACENT CONTROL AREAS.

2. **Sharing INTERCHANGE SCHEDULES details**. The SENDING CONTROL AREA and RECEIVING CONTROL AREA must provide the details of their INTERCHANGE SCHEDULES via the Interregional Security Network as specified in Policy 4.B.

(3. to 011, R5)

3. **Providing tags for approved TRANSACTIONS to the RELIABILITY COORDINATOR.** The SINK CONTROL AREA shall provide its RELIABILITY COORDINATOR the information from the INTERCHANGE TRANSACTION tag electronically for each Approved INTERCHANGE TRANSACTION.

(4. to 012, R12)

4. **INTERCHANGE SCHEDULE confirmation and implementation.** The RECEIVING CONTROL AREA is responsible for initiating the confirmation and implementation of the INTERCHANGE SCHEDULE with the SENDING CONTROL AREA.

(4.1 TO 012, R12)

4.1. **INTERCHANGE SCHEDULE agreement**. The SENDING CONTROL AREA and RECEIVING CONTROL AREA shall agree with each other on the:

- INTERCHANGE SCHEDULE start and end time
- Ramp start time and rate
- Energy profile

This agreement shall be made before either the SENDING CONTROL AREA or RECEIVING CONTROL AREA makes any generation changes to implement the INTERCHANGE SCHEDULE.

4.1.1. **INTERCHANGE SCHEDULE standards.** The SENDING CONTROL AREA and RECEIVING CONTROL AREA shall comply with the INTERCHANGE SCHEDULE Standards in **Policy 3C, "Interchange – Schedule Standards."**

4.1.2. **Operating reliability criteria**. CONTROL AREAS shall operate such that INTERCHANGE SCHEDULES or schedule changes do not knowingly cause any other systems to violate established operating reliability criteria.

(4.1.3 to 012, R1)

4.1.3. DC tie operator. SENDING CONTROL AREAS and RECEIVING CONTROL AREAS shall coordinate with any DC tie operators on the SCHEDULING PATH.

5. Maximum scheduled interchange. The maximum NET INTERCHANGE SCHEDULE between two CONTROL AREAS shall not exceed the lesser of the following:

5.1. Total capacity of facilities. The total capacity of both the owned and arranged-for transmission facilities in service between the two CONTROL AREAS, or

5.2. Total Transfer Capability. The established network Total Transfer Capability (TTC) between the CONTROL AREAS, which considers other transmission facilities available to them under specific arrangements, and the overall physical constraints of the transmission network. Total Transfer Capability is defined in *Available Transfer Capability Definitions and Determination*, NERC, June 1996.

C. Interchange Schedule Standards

Standards

1. **INTERCHANGE SCHEDULE start and end time.(Covered in 012, R1)** INTERCHANGE SCHEDULES shall begin and end at a time agreed to by the SOURCE CONTROL AREA, SINK CONTROL AREA, and the INTERMEDIARY CONTROL AREAS.

2. **Ramp start times.** CONTROL AREAS shall ramp the INTERCHANGE equally across the start and end times of the schedule.

3. **Ramp duration.** CONTROL AREAS shall use the ramp duration established by their INTERCONNECTION as follows unless they agree otherwise:

   (3.1 to 012, R1 a)

   3.1. **INTERCHANGE SCHEDULES within the Eastern and ERCOT INTERCONNECTIONS.** ten-minute ramp duration.

   (3.2 to 012, R1 b)

   3.2. **INTERCHANGE SCHEDULES within the Western INTERCONNECTION.** 20-minute ramp duration.

   3.3. **INTERCHANGE SCHEDULES that cross an INTERCONNECTION boundary.** (Covered in 012, R1)The CONTROL AREAS that implement INTERCHANGE SCHEDULES that cross an INTERCONNECTION boundary must use the same start time and ramp durations.

   3.4. **Exceptions for Compliance with Disturbance Control Standard and Line Load Relief.** Ramp durations for INTERCHANGE SCHEDULES implemented for compliance with NERC's Disturbance Control Standard (recovery from a disturbance condition) and INTERCHANGE TRANSACTION curtailment in response to line loading relief procedures may be shorter, but must be identical for the SENDING CONTROL AREA and RECEIVING CONTROL AREA **[See also Policy 1B, "Generation Control Performance – Disturbance Control Standard," Requirement 2 and subsections on contingency reserve.]**

4. **INTERCHANGE SCHEDULE accounting.** Block accounting shall be used.

D. Interchange Transaction Modifications

Introduction

This section specifies PURCHASING-SELLING ENTITY's, TRANSMISSION PROVIDER'S and CONTROL AREA's rights and requirements for modifying an INTERCHANGE TRANSACTION tag after it has been approved and implemented as described in the preceding sections.

Requirements

(The intent of 1. has been moved to 013, R1)

1. **INTERCHANGE TRANSACTION modification for market-related issues.** The PURCHASING-SELLING ENTITY that submitted an INTERCHANGE TRANSACTION tag may modify an INTERCHANGE TRANSACTION tag that is in progress or scheduled to be started**.** These modifications may be made due to changes in contracts, economic decisions, or other market-based influences. In cases where a market operator is serving as the source or sink for a TRANSACTION, then they shall have the right to effect changes to the energy flow as well (based on the results of the market clearing).

   1.1. Increases. The INTERCHANGE TRANSACTION tag's energy and/or committed transmission reservation(s) profile may be increased to reflect a desire to flow more energy or commit more transmission than originally requested. Necessary transmission must be either available from the earlier TRANSACTION or provided with the increase.

   1.2. Extensions. The INTERCHANGE TRANSACTION tag's energy profile may be extended to reflect a desire to flow energy during hours not previously specified. Necessary transmission capacity must be provided with the extension.

   1.3. Reductions. The INTERCHANGE TRANSACTION tag's energy and/or committed transmission reservation(s) profile may be reduced to reflect a desire to flow less energy or commit less transmission than originally requested. Reductions are used to indicate cancellations and terminations, as well as partial decreases.

   1.4. Combinations of 1.1, 1.2, and 1.3 may be submitted concurrently.

   (1.5 to 013, R1)

   1.5. Coordination responsibilities of the PURCHASING-SELLING ENTITY. The modification must be provided by the PURCHASING-SELLING ENTITY to the following INTERCHANGE TRANSACTION participants:

   - GENERATION PROVIDING ENTITY
   - Generation CONTROL AREA
   - TRANSMISSION PROVIDERS
   - TRANSMISSION CUSTOMERS
   - SCHEDULING ENTITIES
   - Intermediate PURCHASING-SELLING ENTITIES (Title-Holders)
   - Load CONTROL AREA
   - LOAD-SERVING ENTITY
   - Market Redispatch Notification Entities (if specified)
   - Security Analysis Services

FERC Orders 888, 889, 638, and a provider's OATT guide transmission requests. Tagging policy shall not supersede OASIS requirements.

1.6 **INTERCHANGE TRANSACTION modification and evaluation time.** To provide adequate time for INTERCHANGE SCHEDULE implementation, INTERCHANGE TRANSACTION modifications shall be requested and evaluated as specified in Section D of **Appendix 3A1, "Tag Submission and Evaluation Timetable."**

2. **INTERCHANGE TRANSACTION modification for reliability-related issues.** A RELIABILITY COORDINATOR, TRANSMISSION PROVIDER, SCHEDULING ENTITY, GENERATION CONTROL AREA, or LOAD CONTROL AREA may modify an INTERCHANGE TRANSACTION tag that is in progress or scheduled to be started**.** These modifications may be made *only* due to TLR events (or other regional congestion management practices), Loss of Generation, or Loss of Load.

2.1. **Assignment of coordination responsibilities during TLR events.** At such times when TLR is required to ensure reliable operation of the electrical system, and the TLR requires holding or curtailing INTERCHANGE TRANSACTIONS, the LOAD CONTROL AREA is responsible for coordinating the modifications to the appropriate INTERCHANGE TRANSACTION tags. See **Policy 9, Appendix 9C1 "Transmission Loading Relief Procedure – Eastern Interconnection."**

2.1.1. **Reductions**. When a RELIABILITY COORDINATOR must curtail or hold an INTERCHANGE TRANSACTION to respect TRANSMISSION SERVICE reservation priorities or to mitigate potential or actual OPERATING SECURITY LIMIT violations, the RELIABILITY COORDINATOR shall inform the LOAD CONTROL AREA listed on the INTERCHANGE TRANSACTION tag of the greatest reliable level at which the affected INTERCHANGE TRANSACTION may flow.

2.1.2. **Reloads.** At such time as the TLR event allows for the reloading of the transaction, the RELIABILITY COORDINATOR shall inform the LOAD CONTROL AREA listed on the INTERCHANGE TRANSACTION tag of the releasing of the INTERCHANGE TRANSACTION'S limit.

2.2. **Coordination when implementing other congestion management procedures.** As a part of some local and regional congestion management and transmission line overload procedures, the TRANSMISSION PROVIDER or SCHEDULING ENTITY is responsible for implementing curtailment of INTERCHANGE TRANSACTIONS. The TRANSMISSION PROVIDER or affected SCHEDULING ENTITY may adjust the INTERCHANGE TRANSACTION tags as required to implement those local and regional congestion management or transmission overload relief procedures that have been approved by the Region(s) or NERC.

2.2.1. **Reductions.** When a TRANSMISSION PROVIDER or SCHEDULING ENTITY experiences the need to invoke a congestion management or transmission line overload procedure, it may use the curtailment feature of E-Tag to inform the GENERATION CONTROL AREA and the LOAD CONTROL AREA listed on the INTERCHANGE TRANSACTION tag of the greatest reliability limit at which the affected INTERCHANGE TRANSACTION may flow.

2.2.2. **Reloads.** At such time as the need for the congestion management or transmission line overload relief procedure allows for the full or partial reloading of the transaction, the TRANSMISSION PROVIDER or SCHEDULING ENTITY may use the reload feature of E-Tag to inform the GENERATION CONTROL AREA and the LOAD CONTROL AREA listed on the INTERCHANGE TRANSACTION tag that the INTERCHANGE TRANSACTION'S reliability limit has changed.

(2.3 and 2.3.1 to 013, R1)

2.3. Assignment of coordination responsibilities during a loss of generation. At such times when a loss of generation necessitates curtailing INTERCHANGE TRANSACTIONS, the Generation CONTROL AREA is responsible for coordinating the modifications to the appropriate INTERCHANGE TRANSACTION tags.

2.3.1. Reductions. When a generation operator experiences a full or partial loss of generation, it shall notify the HOST CONTROL AREA (the GENERATION CONTROL AREA for the INTERCHANGE TRANSACTION). The HOST CONTROL AREA contacts the GENERATION PROVIDING ENTITY that is responsible for the generation. The GENERATION PROVIDING ENTITY determines what schedule modifications need to be made and may request those modifications as market-based reductions, increases, or extensions (either via the tag author, or directly if the entity is the tag author or a market operator). If the GENERATION PROVIDING ENTITY does not resolve the condition, the HOST CONTROL AREA may at its discretion curtail INTERCHANGE TRANSACTIONS associated with the generation.

2.3.2. Reloads. Upon return of the generation, the generator operator shall notify the HOST CONTROL AREA (the GENERATION CONTROL AREA for the INTERCHANGE TRANSACTION). The HOST CONTROL AREA contacts the GENERATION PROVIDING ENTITY that is responsible for the generation. The GENERATION PROVIDING ENTITY determines what schedule modifications need to be made and may request those modifications as market-based reductions, increases, or extensions (either via the tag author, or directly if the entity is the tag author or a market operator). The HOST CONTROL AREA must release the limits previously imposed on INTERCHANGE TRANSACTIONS associated with the generation (but not override any market-based reductions).

2.4. Assignment of coordination responsibilities during a loss of load. At such times when a loss of load necessitates curtailing INTERCHANGE TRANSACTIONS, the LOAD CONTROL AREA is responsible for coordinating the modifications to the appropriate INTERCHANGE TRANSACTION tags.

2.4.1. Reductions. When a LOAD-SERVING ENTITY experiences a loss of load, it shall notify its HOST CONTROL AREA (the LOAD CONTROL AREA for the INTERCHANGE TRANSACTION) and determine what schedule modifications need to be made. The LOAD-SERVING ENTITY may request those modifications as market-based reductions, increases, or extensions (either via the tag author, or directly if the entity is the tag author or a market operator). If the LOAD-SERVING ENTITY does not notify the HOST CONTROL AREA, the HOST CONTROL AREA may at its discretion curtail INTERCHANGE TRANSACTIONS associated with the load.

2.4.2. Reloads. Upon return of the load, THE LOAD-SERVING ENTITY shall notify its HOST CONTROL AREA (the LOAD CONTROL AREA for the INTERCHANGE TRANSACTION) and determine what schedule modifications need to be made. The LOAD-SERVING ENTITY may request those modifications as market-based reductions, increases, or extensions (either via the tag author, or directly if the entity is the tag author or a market operator). If the LOAD-SERVING ENTITY does not notify the HOST CONTROL AREA, the HOST CONTROL AREA must release the limits previously imposed on INTERCHANGE TRANSACTIONS associated with the load (but not override any market-based reductions).

2.5. Coordination responsibilities for reliability-related issues. The modification must be provided by the requesting CONTROL AREA, TRANSMISSION PROVIDER, or SCHEDULING ENTITY to the following INTERCHANGE TRANSACTION participants:

- Generation Providing Entity
- Generation CONTROL AREA
- TRANSMISSION PROVIDERS
- Transmission Customers
- SCHEDULING ENTITIES
- Intermediate PURCHASING-SELLING ENTITIES (Title-holders)
- Load CONTROL AREA
- LOAD-SERVING ENTITY
- Market Redispatch Notification Entities (if specified)
- Security Analysis Services

2.6. INTERCHANGE TRANSACTION modification and evaluation time. To provide adequate time for INTERCHANGE SCHEDULE implementation, INTERCHANGE TRANSACTION modifications shall be requested and evaluated as specified in **Appendix 3A1, "Tag Submission and Evaluation Timetable** (Attached to 013)

Note 1: Statements from Policies and related appendices that have been moved to Version 0 Standards have been highlighted and the new Version 0 location has been identified as: 1.0 moved to Version 0 Standard 001, Requirement 1, (Simplified as 1.0 to 001, R1). Un-highlighted statements have not been included in Version 0 Standards.
Note 2: In the Version 0 standards, policy statements have been changed to "active voice" wording, and entity titles have been changed to reflect the Functional Model. Other wording changes are intended to be clarification of meaning only.

Policy 4 — System Coordination

Policy Subsections

A. Monitoring System Conditions

Requirements

(1. to 014, R1)

1. **Resources.** The system operator shall be kept informed of all generation and transmission resources available for use.

(2. to 014, R2)

2. **Transmission status and data.** System operators shall monitor transmission line status, MW and MVAR flows, voltage, LTC settings and status of rotating and static reactive resources.

(3. to 014, R3)

3. **Protective relays.** Appropriate technical information concerning protective relays shall be available in each system control center.

(4. to 014, R4)

4. **Other information.** The system operator shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.

(5. to 014, R5)

5. **Monitoring.** Monitoring equipment shall be used to bring to the system operator's attention important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.

(5.1 to 014, R6)

5.1. **Metering.** Each control area shall use sufficient metering of suitable range, accuracy and sampling rate (if applicable) to ensure accurate and timely monitoring of operating conditions under both normal and emergency situations.

(6. to 014, R7)

6. **System frequency.** System operators shall monitor system frequency.

(Guides moved to 014, as attachment)

Guides

1. **Instrumentation.** Reliable instrumentation, including voltage and frequency meters with sufficient range to cover probable contingencies, should be available in each generating plant control room.

2. **Recording devices.** Automatic oscillographs and other recording devices should be installed at key locations and set to standard time to aid in post-disturbance analysis.

3. **Separation.** Monitoring should be sufficient, so that in the event of system separation, both the existence of the separation and the boundaries of the separated areas can be determined.

   3.1. **Frequency information.** Because of possible system separation, frequency information from selected locations should be monitored at the control center.

4. **Transmission monitoring.** Transmission line monitoring should include a means of evaluating the effects of the loss of any significant transmission or generation facilities, both within and outside the control area.

5. **Physical security monitoring.** Where practical, critical unmanned facilities should be monitored for physical security.

6. **Facility outages.** Scheduled outages of generation or transmission facilities should be considered in the monitoring scheme.

7. **Voltage coordination.** Voltage schedules should be coordinated from a central location within each control area and coordinated with adjacent control area

B. Operational Security Information

[Appendix 4B, "Electric System Security Data]

Requirements

1. Use of Electric System Security Data. The Electric System Security Data referred to in this Policy and received over the Interregional Security Network shall be used only for operational security analysis and shall not be made available to nor used by PURCHASING-SELLING ENTITIES in the wholesale merchant function.

(2. to 015, R2)

2. Data confidentiality. All recipients of data from the Interregional Security Network (ISN) shall sign the NERC Confidentiality Agreement for Electric System Security Data. [Appendix 4B, Section B, "Confidentiality Agreement for Electric System Security Data"]

(5. to 015, R4)

3. Data required from Control Areas. Each CONTROL AREA shall provide its RELIABILITY COORDINATOR(S) with the Electric System Security Data that is necessary to allow THE RELIABILITY COORDINATOR(S) to perform its operational security assessments and coordinate reliable operations.

(5. to 015, R4)

3.1. Data. CONTROL AREAS shall provide the types of data as listed in Appendix 4B, "Electric System Security Data, Section A, Electric System Security Data", unless otherwise agreed to by the CONTROL AREAS and their RELIABILITY COORDINATOR(S).

(4. to 015, R3)

4. Data exchange among RELIABILITY COORDINATORS. Upon request, RELIABILITY COORDINATORS shall, via the ISN, exchange with each other Electric Security Data that is necessary to allow the RELIABILITY COORDINATORS to perform their operational security assessments and coordinate their reliable operations.

(4.1 to 015, R3)

4.1. Data. RELIABILITY COORDINATORS shall share with each other the types of data as listed in Appendix 4B, "Electric System Security Data, Section A, Electric System Security Data", unless otherwise agreed to.

(5. to 015, R4)

5. Data exchange among Control Areas. Upon request, Each CONTROL AREA and other entities shall provide to CONTROL AREAS and other entities with immediate responsibility for operational security, the Electric Security Data that is necessary to allow the CONTROL AREA or other such entity to perform its operational security assessment and to coordinate reliable operations.

(5.1 to 015, R4)

5.1. Data. CONTROL AREAS and other entities shall provide the types of data as listed in Appendix 4B, "Electric System Security Data, Section A, Electric System Security Data", unless otherwise agreed to by the CONTROL AREAS and other entities with immediate responsibility for operational security.

(6. to 015, R5)

6. **Information from purchasing-selling entities**. PURCHASING-SELLING ENTITIES shall provide information as requested by their host control areas to enable these control areas to conduct operational security assessments and coordinate reliable operations.

C. Maintenance Coordination

Requirements

(1. to 016, R2)

1. Generator and transmission outages. Scheduled generator and transmission outages that may affect the reliability of interconnected operations shall be planned and coordinated among affected systems and control areas. Special attention shall be given to results of pertinent studies.

(2. to 016, R2)

2. Voltage regulation equipment. Scheduled outages of system voltage regulating equipment, such as automatic voltage regulators on generators, supplementary excitation control, synchronous condensers, shunt and series capacitors, reactors, etc., shall be coordinated as required.

(3. to 016, R3)

3. Telemetering, control, and communications. Scheduled outages of telemetering and control equipment and associated communication channels shall be coordinated between the affected areas.

D. System Protection Coordination

Requirements

(1. to 017, R1)

1. **Protection system familiarity.** System operators shall be familiar with the purpose and limitations of protection system schemes.

(1. to 017, R2)

2. **Notification of failure and corrective action.** If a protective relay or equipment failure reduces system reliability, the proper personnel shall be notified, and corrective action shall be undertaken as soon as possible.

(1. to 017, R3)

3. **Coordination when new or changed.** All new protective systems and all protective system changes shall be coordinated among neighboring systems if the new or changed protective systems affect neighboring systems.

(1. to 017, R4)

4. **Coordination.** Protection systems on major transmission lines and interconnections shall be coordinated with the interconnected systems.

(1. to 017, R5)

5. **Notification of system changes.** Neighboring systems shall be notified in advance of changes in generating sources, transmission, load, or operating conditions, which could require changes in their protection system.

(1. to 017, R6)

6. **Monitoring SPS.** The system operator shall monitor the status of each Special Protection System (SPS) and notify all affected systems of each change in status.

(Guide to 017 as attachment)

Guides

1. **Protection system design.** Protection system design and operations should consider the following:

   1.1. **Minimum complexity.** Protection systems should be of minimum complexity consistent with achieving their purpose.

   1.2. **Redundancy.** Protection systems should have redundancy to allow for their normal maintenance and calibration.

   1.3. **Proper operation.** Protection systems should not normally operate for minor system disturbances, brief overloads, or recoverable system power swings.

   1.4. **High-speed equipment.** High-speed relays, high-speed circuit breakers, and automatic reclosing should be used where studies indicate the application will enhance stability margins. Single-pole tripping or reclosing may be appropriate on some lines.

   1.5. **Automatic reclosing.** Automatic reclosing during out-of-step conditions should be prevented.

   1.6. **Underfrequency relays.** Underfrequency load shedding relays should be coordinated with the generating plant off-frequency relays to assure preservation of system stability and integrity.

1.7. **Reviewing applications.** Protection system applications, settings, and coordination should be reviewed periodically and whenever major changes in generating resources, transmission, load or operating conditions are anticipated.

1.8. **Reviewing protection system adequacy and automated monitoring.** Adequacy of protection system communications channels should be reviewed periodically. Automated channel monitoring and failure alarms should be provided for protective system communications channels, which could cause loss of generation, loss of load, or cascading outages in the event of misoperation or failure.

2. **Protection system implementation, operation, and maintenance.** Each system should implement protection system application, operation, and preventive maintenance procedures, which will enhance their system reliability with the least adverse effect on the Interconnection. These protection system procedures should be provided to all appropriate system personnel and should provide for instruction and training where applicable. Each system should coordinate these procedures with any other systems that could be affected. These procedures should govern:

2.1. **Planning and application of protection systems.**

2.2. **Review of protection systems and settings.**

2.3. **Intended functioning.** Intended functioning of protection systems under normal, abnormal, and emergency conditions.

2.4. **Testing and maintenance.** Regularly scheduled testing and preventive maintenance of relays, vital system protection equipment, and associated components.

2.4.1. **Testing under actual conditions.** The operation of the complete protection system should be tested under conditions as close to actual operating conditions as possible, including actual circuit breaker operation where feasible.

2.4.2. **Testing communications.** Testing protection system communication channels between systems should be coordinated with test results recorded.

2.5. **Analysis.** Analysis of actual protection system operations.

3. **Reviewing abnormal operation.** A prompt investigation should be made to determine the cause of abnormal protection system performance and correct any deficiencies in the protection scheme.

4. **SPS testing.** SPS should be designed for periodic testing without affecting the integrity of the protected power system. They should normally achieve at least the same high level of reliability as that provided by normal protection systems.

5. **SPS security.** SPS should be designed with inherent security to minimize the probability of an improper operation, even with the failure of a primary component.

6. **SPS application review.** Each SPS should be reviewed frequently to determine if it is still required and will still perform the intended functions. Seasonal changes in power transfers may require changes in the SPS or its relay settings.

7. **SPS operation review.** Each SPS operation should be reviewed and analyzed for correctness.

8. **Correcting improper SPS operation.** Prompt action should be taken to correct the causes of an improper operation.

Note 1: Statements from Policies and related appendices that have been moved to Version 0 Standards have been highlighted and the new Version 0 location has been identified as: 1.0 moved to Version 0 Standard 001, Requirement 1, (Simplified as 1.0 to 001, R1). Un-highlighted statements have not been included in Version 0 Standards.
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Policy 5 — Emergency Operations

Version 3

Policy Subsections

A. Operating Authority Responsibilities
B. Communications and Coordination
C. Capacity and Energy Emergencies
D. Transmission
E. System Restoration
F. Disturbance Reporting
G. Sabotage Reporting

Introduction

Operating emergencies on the BULK ELECTRIC SYSTEM may be minor in nature and require small, real-time system adjustments, or they may be major and require fast, preplanned action to avoid the cascading loss of generation or transmission lines, uncontrolled separation, equipment damage, and interruption of customer service.

The integrity and reliability of the BULK ELECTRIC SYSTEM is of paramount importance, and will take precedence above all other aspects including commercial operations; therefore, all OPERATING AUTHORITIES are expected to cooperate and take appropriate action to mitigate the severity or extent of any system emergency.

Terms

BURDEN. Operation of the BULK ELECTRIC SYSTEM that violates or is expected to violate a SOL or IROL in the INTERCONNECTION or that violates any other NERC, Regional, or local operating reliability policies or standards.

OPERATING AUTHORITY. An entity that:

1. Has ultimate accountability for a defined portion of the BULK ELECTRIC SYSTEM to meet one or more of three reliability objectives – generation/demand balance, transmission reliability, and/or emergency preparedness, and

2. Is accountable to NERC and its Regional Reliability Councils for complying with NERC and Regional Policies, and

3. Has the authority to control or direct the operation of generating resources, transmission facilities, or loads, to meet these Policies.

OPERATING AUTHORITIES include such entities as CONTROL AREAS, generation operators and TRANSMISSION OPERATING ENTITIES; it does not include RELIABILITY COORDINATORS.

OPERATING AUTHORITY AREA. That portion of the BULK ELECTRIC SYSTEM under the purview of the OPERATING AUTHORITY.

A. Operating Authority Responsibilities

Requirements

(1. to 007, R1)

1. **Operating within limits.** The OPERATING AUTHORITY shall operate within the SYSTEM OPERATING LIMITS (SOLs) and INTERCONNECTION RELIABILITY OPERATING LIMITS (IROLs).

(2. to 018, R1)

2. **OPERATING AUTHORITY and responsibility.** The OPERATING AUTHORITY shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its OPERATING AUTHORITY AREA and shall exercise specific authority to alleviate operating emergencies.

(2.1 TO 018, R2)

2.1. **Mitigating emergencies.** The OPERATING AUTHORITY shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment (e.g., generators, phase shifters, breakers), shedding firm load, etc.

(2.2 to 018, R3)

2.2. **Complying with Reliability Coordinator directives.** The OPERATING AUTHORITY shall comply with RELIABILITY COORDINATOR directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances the OPERATING AUTHORITY must immediately inform the RELIABILITY COORDINATOR of the inability to perform the directive so that the RELIABILITY COORDINATOR can implement alternate remedial actions.

(3. to 007, R4)

3. **Unknown operating states.** If the OPERATING AUTHORITY enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.

(4. to 018, R4)

4. **Information sharing.** To facilitate emergency assistance, the OPERATING AUTHORITY shall inform other potentially affected OPERATING AUTHORITIES and its RELIABILITY COORDINATOR of real time or anticipated emergency conditions, and take actions to avoid when possible, or mitigate the emergency.

(5. to 018, R5)

5. **Rendering assistance.** The OPERATING AUTHORITY shall render all available emergency assistance requested, provided that the requesting OPERATING AUTHORITY has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements

(6. to 018, R6)

6. **Keeping facilities in service.** The OPERATING AUTHORITY shall not remove BULK ELECTRIC SYSTEM facilities from service if removing those facilities would BURDEN neighboring OPERATING AUTHORITIES unless:

(6.1 to 018, R6)

6.1. The OPERATING AUTHORITY first notifies the adjacent OPERATING AUTHORITIES and coordinates the impact resulting from the removal of the BULK ELECTRIC SYSTEM facility or,

(6.2 to 018, R6)

6.2. When time does not permit such notification and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the OPERATING AUTHORITY shall notify adjacent OPERATING AUTHORITIES at the earliest possible time to ensure OPERATING AUTHORITY coordination.

(7 to 007, R5)

7. **Remaining interconnected.** The OPERATING AUTHORITY shall make every effort to remain connected to the INTERCONNECTION. If the OPERATING AUTHORITY determines that by remaining interconnected, it is in imminent danger of violating System Operating Limits or Interconnected Reliability Operating Limits, the OPERATING AUTHORITY may take such actions, as it deems necessary, to protect its OPERATING AUTHORITY AREA.

(8. covered under Policy 1 Standards)

8. **Complying with control performance standards.** The OPERATING AUTHORITY shall comply with Control Performance Standards and the Disturbance Control Standard [**See Policy 1A, "Control Performance Standard"**] during an emergency.

(9. covered under Policy 3 Standards)

9. **Coordinating interchange.** The OPERATING AUTHORITY shall coordinate INTERCHANGE SCHEDULE changes in accordance with Policy 3, "Interchange," during an emergency.

(10. covered under Policy 1 Standards)

10. **Keeping automatic generation control in service.** Each CONTROL AREA shall maintain automatic generation control equipment operational and in service. [**See Policy 1E, "Automatic Generation Control Standard"**]

(11. to 018, R7)

11. **Taking immediate action.** The OPERATING AUTHORITY shall immediately take action to restore the real and reactive power balance. If the OPERATING AUTHORITY is unable to restore its real and reactive power balance it shall request emergency assistance. If corrective actions or emergency assistance is not adequate to mitigate the real and reactive power balance, then the OPERATING AUTHORITY shall implement firm load shedding.

(12 is covered under Policy 2, Standard 008)

12. **Reducing the effects of power flows.** The OPERATING AUTHORITY shall immediately reduce the effects of power flows through other OPERATING AUTHORITY AREAS if those flows have been identified as contributing to an operating emergency (e.g., resulting in SOL or IROL violations) in those other OPERATING AUTHORITY AREAS.

B. Communications and Coordination

[Appendix 7A – Instructions for Interregional Emergency Telephone Networks]

Requirements

(1. to 019, R1)

1. Communications. The OPERATING AUTHORITY shall have communications (voice and data links) to appropriate entities within its OPERATING AUTHORITY AREA, which are staffed and available to act in addressing a real time emergency condition.

(2. to 019, R2)

2. Notification. The OPERATING AUTHORITY shall notify its RELIABILITY COORDINATOR and all other potentially affected OPERATING AUTHORITIES through predetermined communication paths of any condition that could threaten the reliability of its OPERATING AUTHORITY AREA.

2.1. Using the Interconnection-wide telecommunications system. When a condition is identified that could threaten the reliability of the INTERCONNECTION or when firm load shedding is anticipated, the affected OPERATING AUTHORITY, via its RELIABILITY COORDINATOR, shall utilize the INTERCONNECTION-wide telecommunications network in accordance with Appendix 7A – Regional and Interregional Telecommunication, Subsection A, "NERC Hotline," to convey the following information to others in the INTERCONNECTION:

2.1.1. Insufficient resources. The OPERATING AUTHORITY is unable to purchase capacity or energy to meet its demand and reserve requirements on a day-ahead or hour-by-hour basis.

2.1.2. IROL violation. The OPERATING AUTHORITY recognizes that potential or actual line loadings, and voltage or reactive levels are such that a single CONTINGENCY could threaten the reliability of the INTERCONNECTION. (Once a single CONTINGENCY occurs, the OPERATING AUTHORITY must prepare for the next CONTINGENCY.)

2.1.3. Implementation of emergency actions. The OPERATING AUTHORITY anticipates initiating a 3% or greater voltage reduction, public appeals for load curtailments, or firm load shedding for other than local problems.

2.1.4. Sabotage incident. The OPERATING AUTHORITY suspects or has identified a multi-site sabotage occurrence, or single-site sabotage of a critical facility.

(2.2 to 019, R3)

2.2. Protocols. The OPERATING AUTHORITY shall issue directives in a clear, concise, definitive manner. The OPERATING AUTHORITY shall receive a response from the person receiving the directive who will repeat the information given. The OPERATING AUTHORITY shall acknowledge the statement as correct or repeat the original statement to resolve misunderstandings.

C. Capacity and Energy Emergencies

[Appendix 5C – Energy Emergency Alerts]

Introduction

During a system emergency, the OPERATING AUTHORITY must continue to comply with NERC Control Performance and Disturbance Control Standards as explained in Policy 1, “Generation Control and Performance,” regardless of costs. In other words, the OPERATING AUTHORITY may not rely on the frequency bias of the other CONTROL AREAS in the INTERCONNECTION to provide energy during the emergency because doing so reduces the INTERCONNECTION’S ability to recover its frequency following additional generator failures.

If the OPERATING AUTHORITY cannot comply with the Control Performance and Disturbance Control Standards, then it must immediately implement remedies to do so. These remedies include, but are not limited to:

1. Requesting assistance from other CONTROL AREAS

2. Declaring an ENERGY EMERGENCY through its RELIABILITY COORDINATOR

3. Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

Requirements

(1. to 020, R4)

1. Anticipating capacity or energy emergency. A CONTROL AREA anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.

(2. to 020, R3)

2. Returning ACE to Acceptable Levels. In the event of a capacity or energy emergency, generation and transmission facilities shall be used to the fullest extent practicable to comply with the CPS and DCS as defined in Policy 1A, “Control Performance Standard.” Using bias variables to “cover up” energy emergency problems is prohibited.

(2.1 to 020, R5)

2.1. Mitigating an energy emergency. Once the control areas has exhausted the following steps:

- All available generating capacity is loaded, and
- All operating reserve is utilized, and
- All interruptible load and interruptible exports have been interrupted, and
- All emergency assistance from other control areas is fully utilized, and
- Its ACE is negative and cannot be returned to zero in the next fifteen minutes, then

(2.1.1 to 020, R5)

2.1.1. The CONTROL AREA shall manually shed firm load without delay to return its ACE to zero.

(2.2.2 to 020, R5)

2.1.2. The deficient CONTROL AREA shall declare an EMERGENCY ENERGY Alert in accordance with Appendix 5C.

(2.2 to 020, R3)

2.2. **Using INTERCONNECTION'S bias.** The deficient CONTROL AREA may only use the assistance provided by the INTERCONNECTION'S frequency bias for the time needed to implement corrective actions.

(Section 3 is covered in the appendix that is attached to 020)

3. **Elevating Transmission Service Priority within the Eastern INTERCONNECTION.** When a TRANSMISSION PROVIDER expects to elevate the transmission service priority of an INTERCHANGE TRANSACTION from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff **[**See **Appendix 9C1, "Transmission Loading Relief Procedure"** for explanation of Transmission Service Priorities**]:**

3.1. The LOAD-SERVING ENTITY served by the CONTROL AREA or TRANSMISSION PROVIDER must request its RELIABILITY COORDINATOR to initiate an ENERGY EMERGENCY ALERT. **[See Appendix 5C, "Energy Emergency Alerts"]**

3.1.1. This Alert must be posted on the NERC Web site, and include the expected total MW that may have its TRANSMISSION SERVICE priority changed.

3.2. EEA 1 will be used to *forecast* the change of the priority of TRANSMISSION SERVICE of an INTERCHANGE TRANSACTION on the system from Priority 6 to Priority 7.

3.3. EEA 2 will be used to *announce* the change of the priority of TRANSMISSION SERVICE of an INTERCHANGE TRANSACTION on the system from Priority 6 to Priority 7.

4. **Unilateral action.** The OPERATING AUTHORITY shall not unilaterally adjust generation in an attempt to return INTERCONNECTION frequency to normal beyond that supplied through frequency bias action and INTERCHANGE SCHEDULE changes. Such unilateral adjustment may overload transmission facilities.

D. Transmission

Introduction

This policy:

1. Summarizes the authority, information and tools required by SYSTEM OPERATORS responsible for the reliability of the INTERCONNECTIONS.

2. Identifies the accountability for developing and implementing procedures to alleviate SYSTEM OPERATING LIMIT (SOL) and INTERCONNECTED RELIABILITY OPERATING LIMIT (IROL) violations.

3. Describes the requirement to develop procedures for the curtailment and restoration of transmission service.

Requirements

(1. to 021, R1)

1. **Mitigating SOL and IROL violations.** The OPERATING AUTHORITY experiencing or contributing to an SOL or IROL violation shall take immediate steps to relieve the condition, which may include firm load shedding.

(2. to 021, R2)

2. **OPERATING AUTHORITIES shall not BURDEN others.** The OPERATING AUTHORITY shall ensure it operates to prevent the likelihood that a disturbance, action, or non-action will result in a SOL or IROL violation in its OPERATING AUTHORITY AREA or another area of the INTERCONNECTION. In instances where there is a difference in derived operating limits, the BULK ELECTRIC SYSTEM shall always be operated to the most limiting parameter.

(3. TO 021, R3)

3. The OPERATING AUTHORITY shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered.

(4. to 021, R3)

4. Neighboring OPERATING AUTHORITIES and RELIABILITY COORDINATORS impacted by the disconnection shall be notified prior to switching, if time permits, otherwise, immediately thereafter.

(5 to 021, R4)

5. The OPERATING AUTHORITY shall have sufficient information and analysis tools to determine the cause(s) of SOL violations. This analysis shall be conducted in all operating timeframes. The OPERATING AUTHORITY shall use the results of these analyses to immediately mitigate the SOL violation.

E. System Restoration

[Policy 6D – Operations Planning–System Restoration]
[Electric System Restoration Reference Document]

Introduction

After a system collapse, restoration shall begin when the RELIABILITY COORDINATOR and its affected OPERATING AUTHORITY(IES) determine that they can proceed in an orderly and secure manner. RELIABILITY COORDINATORS and affected OPERATING AUTHORITIES shall coordinate their restoration actions. Restoration priority shall be given to the station supply of power plants and the transmission system. Even though the restoration is to be expeditious, OPERATING AUTHORITIES shall avoid premature action to prevent a re-collapse of the BULK ELECTRIC SYSTEM.

Customer load shall be restored as generation and transmission equipment becomes available, recognizing that load and generation must remain in balance at normal frequency as the BULK ELECTRIC SYSTEM is restored.

Requirements

(1 and 1.1 to 1.6 to 025, R10)

1. **Returning to normal operations.** Following a disturbance in which one or more OPERATING AUTHORITY AREAS become isolated, steps shall begin immediately to return the BULK ELECTRIC SYSTEM to normal:

   1.1. **Extent of isolated** BULK ELECTRIC SYSTEM**.** The OPERATING AUTHORITY working in conjunction with its RELIABILITY COORDINATOR shall determine the extent and condition of the isolated area(s).

   1.2. **Frequency restoration.** The OPERATING AUTHORITY shall then take the necessary action to restore BULK ELECTRIC SYSTEM frequency to normal, including adjusting generation, placing additional generators on line, or load shedding.

   1.3. **INTERCHANGE SCHEDULE review.** The RELIABILITY COORDINATOR and affected CONTROL AREAS shall immediately review the INTERCHANGE SCHEDULES between those CONTROL AREAS or fragments of those CONTROL AREAS within the separated area and make adjustments as needed to facilitate the restoration. The affected Control Areas shall make all attempts to maintain the adjusted INTERCHANGE SCHEDULES whether generation control is manual or automatic.

   1.4. **Resynchronizing.** When voltage, frequency, and phase angle permit, the OPERATING AUTHORITY may resynchronize the isolated area(s) with the surrounding area(s), upon notifying its RELIABILITY COORDINATOR and adjacent OPERATING AUTHORITIES, and considering the size of the area being reconnected and the capacity of the transmission lines effecting the reconnection. (The OPERATING AUTHORITY'S restoration plan should consider the number of synchronizing points across the system.)

   1.5. **Off-site supply for nuclear plants.** The OPERATING AUTHORITY shall give high priority to restoration of off-site power to nuclear stations.

   1.6. **Load Shedding.** Load shall be shed in neighboring OPERATING AUTHORITY areas, where required, to permit successful interconnected system restoration.

F. Disturbance Reporting

[Appendix 5F – Reporting Requirements for Major Electric System Emergencies]

Introduction

Disturbances or unusual occurrences that jeopardize the operation of the BULK ELECTRIC SYSTEM, and result, or could result, in system equipment damage, or customer interruptions, must be studied in sufficient depth to increase industry knowledge of electrical interconnection mechanics to minimize the likelihood of similar events in the future. It is important that the facts surrounding a disturbance shall be made available to RELIABILITY COORDINATORS, and OPERATING AUTHORITIES, Regional Councils, NERC, and regulatory agencies entitled to the information.

Requirements

(1. to 022, R1)

1. Regional Council Reporting Procedures. Each Regional Council shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final disturbance reports.

(2. to 022, R2)

2. Analyzing disturbances. BULK ELECTRIC SYSTEM disturbances shall be promptly analyzed by the affected OPERATING AUTHORITIES.

(3 to 022, R3)

3. Disturbance reports. Based on the NERC and DOE disturbance reporting requirements, those OPERATING AUTHORITIES responsible for investigating the incident shall provide a preliminary written report to their Regional Council and NERC.

(3.1 to 022, R3)

3.1. Preliminary written reports. Either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Interconnected Reliability Operating Limit and Preliminary Disturbance Report form shall be submitted by the affected OPERATING AUTHORITY within 24 hours of the disturbance or unusual occurrence. Certain events (e.g. near misses) may not be identified until some time after they occur. Events such as these should be reported within 24 hours of being recognized.

(3.2 to 022, R3)

3.2. Preliminary reporting during adverse conditions. Under certain adverse conditions, e.g. severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Interconnected Reliability Operating Limit and Preliminary Disturbance Report within 24 hours. In such cases, the affected OPERATING AUTHORITY shall notify its Regional Council(s) and NERC promptly and verbally provide as much information as is available at that time. The affected OPERATING AUTHORITY shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report.

(3.3 to 022, R3)

3.3. **Final written reports.** If in the judgment of the Regional Council, after consultation with the OPERATING AUTHORITY in which a disturbance occurred, a final report is required, the affected OPERATING AUTHORITY shall prepare this report within 60 days. As a minimum, the final report shall have a discussion of the events and its cause, the conclusions reached, and recommendations to prevent recurrence of this type of event. The report shall be subject to Regional Council approval.

4. **Notifying NERC.** The NERC Disturbance Reporting Requirements, shown in **Appendix 5F, Sections A and B**, are the minimum requirements for reporting disturbances, unusual occurrences, and voltage excursions to NERC.

5. **Notifying DOE.** The U.S. Department of Energy's most recent Emergency Incident and Disturbance Reporting Requirements, outlined in **Appendix 5F, Section C,** are the minimum requirements for U.S. utilities and other entities subject to Section 13(b) of the Federal Energy Administration Act of 1974. Copies of these reports shall be submitted to NERC at the same time they are submitted to DOE.

(6. to 022, R4)

6. **Assistance from NERC Operating Committee (OC) and the Disturbance Analysis Working Group (DAWG).** When a BULK ELECTRIC SYSTEM disturbance occurs, the Regional Council's OC and DAWG representatives shall make themselves available to the OPERATING AUTHORITY immediately affected to provide any needed assistance in the investigation and to assist in the preparation of a final report.

(7. to 022, R5)

7. **Final report recommendations.** The Regional Council shall track and review the status of all final report recommendations at least twice each year to ensure they are being acted upon in a timely manner. If any recommendation has not been acted on within two years, or if Regional Council tracking and review indicates at any time that any recommendation is not being acted on with sufficient diligence, the Regional Council shall notify the NERC Planning Committee and Operating Committee of the status of the recommendation(s) and the steps the Regional Council has taken to accelerate implementation.

G. Sabotage Reporting

Introduction

Disturbances or unusual occurrences, suspected or determined to be caused by sabotage, shall be reported to the appropriate systems, governmental agencies, and regulatory bodies.

Requirements

(1. to 023, R1)

1. **Recognizing sabotage.** Each OPERATING AUTHORITY shall have procedures for the recognition of and for making its SYSTEM OPERATORS aware of sabotage events on its facilities and multi-site sabotage affecting larger portions of the INTERCONNECTION. Procedures shall also be established for the communication of information concerning sabotage events to appropriate parties in the INTERCONNECTION**.**

(2. to 023, R2)

2. **Reporting guidelines.** SYSTEM OPERATORS shall be provided with guidelines including lists of utility contact personnel, for reporting disturbances due to sabotage events.

(3. to 023, R3)

3. **Contact with FBI and RCMP.** OPERATING AUTHORITIES shall establish communications contacts with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and develop reporting procedures as appropriate to their circumstances.

(Guides to 023, attachment)

Guides

1. **Information to media.** OPERATING AUTHORITIES should establish procedures for supplying sabotage-related information to the media. Release of this information must be coordinated with the appropriate FBI or RCMP personnel.

Note 1: Statements from Policies and related appendices that have been moved to Version 0 Standards have been highlighted and the new Version 0 location has been identified as: 1.0 moved to Version 0 Standard 001, Requirement 1, (Simplified as 1.0 to 001, R1). Un-highlighted statements have not been included in Version 0 Standards.

Note 2: In the Version 0 standards, policy statements have been changed to "active voice" wording, and entity titles have been changed to reflect the Functional Model. Other wording changes are intended to be clarification of meaning only.

Policy 6 – Operations Planning

Version 2

Policy Subsections

A. **Normal Operations**
B. **Emergency Operations**
C. **Load Shedding**
D. **System Restoration**
E. **Continuity of Operations**

Introduction

(Following paragraph to 024, R1)
Each OPERATING AUTHORITY shall maintain a set of current plans that are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each OPERATING AUTHORITY is responsible for using available personnel and system equipment to implement these plans to assure that interconnected systems reliability will be maintained.

(Following paragraph to 024, R2)
SYSTEM OPERATORS shall participate in the system planning and design study processes so that these studies will contain the SYSTEM OPERATORS' perspective and the SYSTEM OPERATORS will know the intended planning purpose.

A. Normal Operations

Requirements

(1. to 024, R3)

1. Operations planning coordination. Each OPERATING AUTHORITY shall plan its current-day, next-day, and seasonal operations in coordination with neighboring OPERATING AUTHORITIES so that normal INTERCONNECTION operation will proceed in an orderly and consistent manner.

(1.1 to 024, R4)

1.1. Each transmission and generation owner shall coordinate its current-day, next-day, and seasonal operations with its host CONTROL AREA(s).

(1.2 to 024, R5)

1.2. Each CONTROL AREA shall coordinate its current-day, next-day, and seasonal operations with neighboring CONTROL AREAS and with its RELIABILITY COORDINATOR.

2. Operations planning objectives. Each OPERATING AUTHORITY shall plan to meet:

(2.1 to 024, R6)

2.1. Planned changes in system configuration, generation dispatch, interchange scheduling and demand patterns.

(2.2 to 024, R7)

2.2. Unplanned changes in system configuration and generation dispatch (at a minimum N-1 CONTINGENCY planning) in accordance with NERC, Regional, and local reliability requirements.

(2.3 to 024, R8)

2.3. Capacity and energy reserve requirements, including the deliverability/capability for any single CONTINGENCY.

(2.4 to 024, R9)

2.4. Voltage and/or reactive limits, including the deliverability/capability for any single CONTINGENCY.

(2.5 to 024, R10)

2.5. INTERCHANGE SCHEDULES. All generator owners shall operate their plant so as to adhere to ramp schedules.

(2.6to 024, R11)

2.6. SYSTEM OPERATING LIMITS

(3. to 024, R12)

3. **BULK ELECTRIC SYSTEM studies.** The CONTROL AREA shall perform seasonal, next-day, and current-day BULK ELECTRIC SYSTEM studies to determine SYSTEM OPERATING LIMITS. Neighboring CONTROL AREAS shall utilize identical SYSTEM OPERATING LIMITS for common facilities. These BULK ELECTRIC SYSTEM studies shall be updated as necessary to reflect current system conditions. The results of BULK ELECTRIC SYSTEM studies shall be made available to the CONTROL AREA operators and to its RELIABILITY COORDINATOR.

(4. TO 024, R13

4. **Total Transfer Capability or Available Transfer Capability and transmission coordination.** The CONTROL AREA shall include known SOLs or IROLs within its area and neighboring areas in the determination of transfer capabilities, in accordance with filed tariffs and/or regional TTC/ATC calculation processes.

(5. to 024, R14)

5. **Generator capability.** At the request of the CONTROL AREA, generator operators shall perform generating capability verification that shall include, among other variables, weather, ambient air and water conditions, and fuel quality and quantity, and provide the results to the CONTROL AREA operator as requested. (See also Planning Standard II.B.S1)

(6. to 024, R16)

6. **Communication of facility status.** (Note: in the following Requirements, the term "immediately" shall be defined as "without any intentional time delay.")

(6.1 to 024, R16)

6.1. Generator operators shall immediately notify their CONTROL AREA operators of changes in capabilities and characteristics including but not limited to:

(6.1.1 to 024, R16)

6.1.1. Changes in real and reactive output capabilities,

(6.1.2 to 024, R16)

6.1.2. Automatic Voltage Regulator status and mode setting

(6.2 to 024, R16)

6.2. Generation operators shall provide a forecast of expected real power output to their CONTROL AREAS to assist in operations planning at the CONTROL AREA'S request (e.g. a seven-day forecast of real output).

(6.3 to 024, R17)

6.3. Transmission operators shall immediately notify their CONTROL AREA operators of changes in capabilities and characteristics including but not limited to:

(6.3.1 to 024, R17)

6.3.1. Changes in transmission facility status

(6.3.2 to 924, R17)

6.3.2. Changes in transmission facility rating

(6.4 to 024, R18)

6.4. CONTROL AREA shall immediately communicate the above information to their RELIABILITY COORDINATOR.

(6.5 to 024, R19)

6.5. **Uniform line identifiers.** Neighboring OPERATING AUTHORITIES shall use uniform line identifiers when referring to transmission facilities of an interconnected network.

(7. to 024, R20)

7. **Computer models.** The CONTROL AREA shall maintain accurate computer models utilized for analyzing and planning system operations.

B. Emergency Operations

Introduction

Each OPERATING AUTHORITY shall develop, maintain, and implement a set of plans consistent with NERC Operating Policies to mitigate operating emergencies. These plans shall be coordinated with other OPERATING AUTHORITIES, CONTROL AREAS, and RELIABILITY COORDINATORS as appropriate.

Requirements

(1. to 025, R1)

1. Agreements for emergency assistance. CONTROL AREAS shall have operating agreements with adjacent CONTROL AREAS that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote CONTROL AREAS.

(2. to 025, R2)

2. Staffing and training. The CONTROL AREA shall be staffed with adequately trained operating personnel. Training for operators shall meet or exceed a minimum of 5 days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.

(3. to 025, R3)

3. Load shedding to prevent separation. The OPERATING AUTHORITY shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the OPERATING AUTHORITY will implement load reduction in sufficient amount and time to mitigate the IROL violation before system separation or collapse would occur. The load reduction plan must be capable of being implemented within 30 minutes.

(4. through 4.4 to 025, R4)

4. Emergency plan types. The OPERATING AUTHORITY shall have emergency plans that address the following:

4.1. Insufficient Generating Capacity

4.2. Transmission

4.3. Load Shedding

4.4. System Restoration

(5. to 5.4 to 025, R5)

5. Emergency plan elements. Each CONTROL AREA shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, the CONTROL AREA'S emergency plans shall include:

5.1. Communications. Communications protocols to be used during emergencies.

5.2. Controlling Actions. List of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC established timelines, shall be one of the controlling actions.

5.3. Coordinating Tasks. The tasks to be coordinated with and among adjacent CONTROL AREAS and OPERATING AUTHORITIES within the CONTROL AREA.

5.4. Staffing. Staffing levels for the emergency.

(6. to 025, R6)

6. Emergency plan review and update. The OPERATING AUTHORITY shall annually review and update each emergency plan. The OPERATING AUTHORITY shall provide a copy of its updated emergency plans to neighboring OPERATING AUTHORITIES and to its RELIABILITY COORDINATOR.

(7. through 7.4 to 025, R7)

7. Emergency Plan Coordination. The OPERATING AUTHORITY shall coordinate its emergency plans with other OPERATING AUTHORITIES, CONTROL AREAS, and RELIABILITY COORDINATORS as appropriate. This coordination includes the following steps:

7.1. Communications. Establish and maintain reliable communications between interconnected systems.

7.2. Interchange agreements. Arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.

7.3. Maintenance coordination. Coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)

7.4. Energy deliveries. Arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

(Guides to 025, as attachment)

Guides

Emergency plans should consider the following items:

1. Fuel supply and inventory. An adequate fuel supply and inventory plan which recognizes reasonable delays or problems in the delivery or production of fuel.

2. Fuel switching. Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.

3. Environmental constraints. Plans to seek removal of environmental constraints for generating units and plants.

4. System energy use. The reduction of the system's own energy use to a minimum.

5. Public appeals. Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

6. **Load management.** Implementation of load management and voltage reductions, if appropriate.

7. **Optimize fuel supply.** The operation of all generating sources to optimize the availability.

8. **Appeals to customers to use alternate fuels.** In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.

9. **Interruptible and curtailable loads.** Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.

10. **Maximizing generator output and availability.** The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.

11. **Notifying IPPs.** Notification of cogeneration and independent power producers to maximize output and availability.

12. **Requests of government.** Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.

13. **Load curtailment.** A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.

14. **Notification of government agencies.** Notification of appropriate government agencies as the various steps of the emergency plan are implemented.

15. **Utilization of Energy Emergency Alert procedures as specified in Appendix 5C.**

16. **Generation redispatch options.**

17. **Transmission reconfiguration options.**

18. **Utilization of Special Protection Schemes.**

19. **Local or INTERCONNECTION-wide transmission loading relief procedures.**

20. **Reserve sharing.**

C. Load Shedding

Introduction

(Introductory paragraph to 026, R1)

After taking all other remedial steps, an OPERATING AUTHORITY or CONTROL AREA whose integrity is in jeopardy due to insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the INTERCONNECTION.

Requirements

(1. to 026, R2)

1. **Plans for automatic load shedding.** Each OPERATING AUTHORITY shall establish plans for automatic load shedding.

(1.1 to 026, R3)

1.1. **Coordination.** Load shedding plans shall be coordinated among the interconnected OPERATING AUTHORITY AREAS.

(1.2 to 026, R4)

1.2. **Frequency or voltage level.** Automatic load shedding shall be initiated at the time the system frequency or voltage has declined to an agreed-to level.

(1.2.1 to 026, R4)

1.2.1. **Load shedding steps.** Automatic load shedding shall be in steps related to one or more of the following: frequency, rate of frequency decay, voltage level, rate of voltage decay or power flow levels.

(1.2.2 to 026, R5)

1.2.2. **Minimizing risk.** The load shed in each step shall be established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

(1.2.3 to 026, R6)

1.2.3. **Underfrequency load shedding on separation.** After an OPERATING AUTHORITY AREA or CONTROL AREA separates from the INTERCONNECTION, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the OPERATING AUTHORITY or CONTROL AREA shall shed additional load.

(1.2.4 to 026, R7)

1.2.4. **Coordination with generator, et al, tripping.** Automatic load shedding shall be coordinated throughout the OPERATING AUTHORITY AREAS with underfrequency isolation of generating units, tripping of shunt capacitors, and other automatic actions which will occur under abnormal frequency, voltage, or power flow conditions.

(2. to 026, R8)

2. **Plans for manual load shedding.** Each OPERATING AUTHORITY or CONTROL AREA shall have plans for SYSTEM OPERATOR-controlled manual load shedding to respond to real-time emergencies. The manual load shedding shall be capable of being implemented in a timeframe to adequately respond to the emergency.

(Guides have been attached to 026)

Guides

1. **Load shedding studies.** Automatic load shedding plans should be based on studies of system dynamic performance, simulating the greatest probable imbalance between load and generation.

    1.1. **Unacceptable results.** Plans to shed load automatically should be examined to determine if unacceptable overfrequency, overvoltage, or transmission overloads might result.

        1.1.1. **Action on overfrequency.** If overfrequency is likely, the amount of load shed should be reduced or automatic overfrequency load restoration should be provided.

        1.1.2. **Action on overvoltage.** If overvoltages are likely, the load-shedding program should be modified to minimize that probability.

2. **Local area considerations.** When scheduling load to be shed automatically, the system should consider its local area requirements and transmission capabilities between areas.

3. **Automatic isolation plan.** A generation-deficient CONTROL AREA may establish an automatic isolation plan in lieu of automatic load shedding, if by doing so it removes the BURDEN it has imposed on the INTERCONNECTION. This isolation plan may be used only with the consent of neighboring systems, and if it leaves the remaining BULK ELECTRIC SYSTEM intact.

D. System Restoration

[Policy 5E – Emergency Operations–System Restoration]
[Electric System Restoration Reference Document]

Introduction

(Introductory paragraph to 027, R1)
Each OPERATING AUTHORITY shall have and periodically update a logical plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of the system. This plan shall be coordinated with other OPERATING AUTHORITIES in the INTERCONNECTION to assure a consistent INTERCONNECTION restoration plan.

A reliable and adequate source of startup power for generating units shall be provided. Where sources are remote from the generating unit, instructions shall be issued to expedite availability. Generation restoration steps shall be verified by actual testing whenever possible.

System restoration procedures shall be verified by actual testing or by simulation.

Requirements

(1. to 027, R2)

1. Restoration plan. Each OPERATING AUTHORITY shall have a restoration plan with necessary operating instructions and procedures to cover emergency conditions, including the loss of vital telecommunications channels.

(1.1 to 027, R3)

1.1. Restoration plan update. The OPERATING AUTHORITY shall review and update its restoration plan at least annually, and whenever it makes changes in the power system network, and to correct deficiencies found during the simulated restoration exercises.

(1.2 to 027, R4)

1.2. Restoring the INTERCONNECTION. The OPERATING AUTHORITY'S restoration plans must be developed with the intent of restoring the integrity of the INTERCONNECTION.

(1.3 to 027, R5)

1.3. Coordination. The OPERATING AUTHORITY shall coordinate its restoration plans with neighboring OPERATING AUTHORITIES.

(1.4 to 027, R6)

1.4. Testing telecommunications. The OPERATING AUTHORITY will periodically test its telecommunication facilities needed to implement the restoration plan.

(2. to 027, R7)

2. SYSTEM OPERATOR training. The OPERATING AUTHORITY shall train its operating personnel in the implementation of the restoration plan. Such training shall include simulated exercises, if practicable.

(3. TO 027, R8)

3. **Procedure testing.** The OPERATING AUTHORITY shall verify its restoration procedures by actual testing or by simulation.

(4. to 027, R9)

4. **Blackstart capability.** The OPERATING AUTHORITY shall ensure the availability and location of Blackstart capability within its OPERATING AUTHORITY AREA to meet the needs of the restoration plan.

(Guides have been attached to 027)

Guides

1. **Operation at abnormal voltage and frequency.** Generators and their auxiliaries should be able to operate reliably at abnormal voltages and frequencies.

2. **Generator shutdown and restart.** Emergency sources of power should be available to facilitate safe shutdown, enable turning gear operation, minimize the likelihood of damage to either generating units or their auxiliaries, maintain communications, and expedite restarting.

3. **Emergency power source.** Each generating plant should have a source of emergency power to expedite restarting.

- **3.1.** Hydroelectric plants should have internal provisions for restarting.

- **3.2.** Station service busses. Where station service generators are used in parallel with the system, station auxiliary busses should be separated automatically from the system before the frequency has decayed sufficiently to adversely affect the station service units.

- **3.3.** Station service and area security. The effect of station service generators on area security should be considered before they are shut down for economy.

- **3.4.** Outside startup power source. Where an outside source of power is necessary for generating unit startup, switching procedures should be prearranged and periodically reviewed with SYSTEM OPERATORS and other operating personnel.

4. **Startup and shutdown plans.** Each CONTROL AREA should have written plans for orderly start-up and shutdown of the generating units.

- **4.1.** **Updates.** These plans should be updated when required.

- **4.2.** **Drills.** Drills should be held periodically to assure that plant operators are familiar with the plans.

5. **Blackstart testing.** Periodic tests should be made to verify blackstart capability.

6. **Synchroscope calibration.** All synchroscopes should be calibrated in degrees, and phase angle differences at interconnection points should be communicated in degrees.

7. **Synchronizing locations and procedures.** SYSTEM OPERATORS should know the preplanned synchronizing locations and procedures. Procedures should provide for alternative action to be taken in case of lack of information or loss of communication channels that would affect resynchronizing.

8. **Protection systems.** Proper protection systems should be considered in the restoration sequence. Relay polarization sources should be maintained during the process.

9. **Telecommunications considerations.** Backup voice telecommunications facilities, including emergency power supplies and alternate telecommunications channels, should be provided to assure coordinated control of operations during the restoration process.

10. **Master trip points.** Control centers using SCADA systems should consider providing master trip points for each station to expedite the restoration process.

E. Continuity of Operations

[Backup Control Center Reference Document] (The Back Up Control Center Reference document **has not been** attached to 028)

(Note: the requirements fro continuity of operations is covered in Compliance Template P6T2, and the wording from that template has been used in the development of Version 0 Standard 028, Plans for Loss of Control center Functionality)

Requirement

CONTROL AREAS and RELIABILITY COORDINATORS shall have a plan to continue reliability operations in the event its control center becomes inoperable.

Guides

1. **Must not BURDEN the INTERCONNECTION.** The standards of Policy 1, "Generation Control and Performance," should be considered when developing the plan to continue operation so that the CONTROL AREA will not be a BURDEN to the INTERCONNECTION if its own control center becomes inoperable.

    1.1. **Location of backup center.** If the CONTROL AREA has a backup control center, it should be remote from the primary control center site.

Note 1: Statements from Policies and related appendices that have been moved to Version 0 Standards have been highlighted and the new Version 0 location has been identified as: 1.0 moved to Version 0 Standard 001, Requirement 1, (Simplified as 1.0 to 001, R1). Un-highlighted statements have not been included in Version 0 Standards.
Note 2: In the Version 0 standards, policy statements have been changed to "active voice" wording, and entity titles have been changed to reflect the Functional Model. Other wording changes are intended to be clarification of meaning only.

Policy 7 — Telecommunications

Version 1b

[Geomagnetic Disturbance Reference Document]

Policy Subsections

A. Facilities

[Appendix 7A —Telecommunications Between Participating Entities] (Attached to Version 0 Standard 029)

Requirements

(1. to 029, R1)

1. Reliable and Secure Telecommunications Networks. Each Participating Entity[1] shall provide adequate and reliable telecommunications facilities[2] internally and with other Participating Entities to assure the exchange of INTERCONNECTION and operating information necessary to maintain reliability. Where applicable, these facilities shall be redundant and diversely routed. Adequacy, redundancy, reliability and applicability are determined by each application's requirements.

2. Interregional Security Network. All RELIABILITY AREAS and Participating Entities shall participate in the Interregional Security Network as described in Appendix 7A, Section B, "Interregional Security Network," and provide the Operational Security Information as explained in Policy 4B, "Required Data Exchange."

(3. to 029, R2)

3. Reliability of Telecommunications Facilities. Vital telecommunications facilities shall be managed, alarmed, tested and/or actively monitored. Special attention shall be given to emergency telecommunications facilities and equipment not used for routine communications.

[1] "Participating entity" refers to any system, operating, market or regional entity responsible for ensuring reliable and adequate system operations subject to NERC Operating Policy.

[2] "Telecommunications facilities" refers to all voice and data, wire and wireless facilities used for the exchange of information.

B. System Operator Telecommunication Procedures

Requirements

(1. to 029, R3)

1. **Telecommunications coordination**. Each Participating Entity shall provide a means to coordinate telecommunications among the systems in that area. This coordination shall include the ability to investigate and recommend solutions to telecommunications problems within the area and with other areas.

(2. to 029, R4)

2. **English language standard.** Unless agreed to otherwise, English shall be the language for all communications between and among SYSTEM OPERATORS and SYSTEM PERSONNEL responsible for the real-time generation control and operation of the interconnected BULK ELECTRIC SYSTEM. Operations internal to the OPERATING AUTHORITY may use an alternate language.

C. Loss of Telecommunications

Requirements

(1. to 029, R5)

1. **Written instructions.** Each Participating Entity shall have written operating instructions and procedures to enable continued operation of the system during loss of telecommunications facilities.

D. Security

Requirements

(1. to 029, R6)

1. **NERCnet security**. Participating entities shall adhere to the requirements set forth in Appendix 7A, Attachment 2 – NERCnet Security Policy.

(NERCnet Security Policy has been attached to Version 0 Standard 029)

Note 1: Statements from Policies and related appendices that have been moved to Version 0 Standards have been highlighted and the new Version 0 location has been identified as: 1.0 moved to Version 0 Standard 001, Requirement 1, (Simplified as 1.0 to 001, R1). Un-highlighted statements have not been included in Version 0 Standards.

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Policy 8 – Operating Personnel and Training

Version 2, Draft 4.2

Policy Subsections

A. Responsibility and Authority
B. Training
C. Certification

This Policy defines the responsibilities, authorities and the certification standards, and the training requirements of SYSTEM OPERATORS.

A. Responsibility and Authority

(Standard to 030, R1)

Standard

Responsibilities and Authorities. The SYSTEM OPERATOR shall have the responsibility and authority to implement real-time actions that ensure the stable and reliable operation of the BULK ELECTRIC SYSTEM.

B. Training

[Appendix 8B1, Suggested Items for System Operator Training Courses.]

Requirements

(1. to 031, R1

1. **SYSTEM OPERATOR Training.** Each OPERATING AUTHORITY shall provide its SYSTEM OPERATORS with a coordinated training program that is designed to promote reliable operation. This program shall include:

   (1.1 to 031, R1)

   1.1. Objectives. Objectives based on *NERC Operating Policies*, Regional Council policies, OPERATING AUTHORITY operating procedures, and applicable regulatory requirements. These objectives shall reference the knowledge and competencies needed to apply those policies, procedures, and requirements to normal, emergency, and restoration conditions.

   (1.2 to 031, R1)

   1.2. Training Plan. A plan for the initial and continuing training that addresses required knowledge and competencies and their application in system operations.

   (1.3 to 031, R1)

   1.3. Training time. Dedicated training time for all SYSTEM OPERATORS to ensure their operating proficiency.

   (1.4 to 031, R1)

   1.4. Training staff. Individuals competent in both knowledge of system operations and instructional capabilities.

   (1.5 to 1.7 requirements are covered in the 031 Measures and Compliance Assessment Process notes added from P8T3 Compliance Template.)

   1.5. Verification of achievement. Verification that all trainees have successfully demonstrated attainment of all required training objectives, including documented assessment of their training progress.

   1.6. Evaluation. Evaluations of training effectiveness to enhance further training.

   1.7. Review. Periodic review to ensure that training materials are technically accurate and complete and to ensure that the training program continues to meet its objectives.

(Guide attached to 031)

Guides

1. **Practice situations.** Each OPERATING AUTHORITY should periodically practice simulated emergencies. The scenarios included in practice situations should represent a variety of operating conditions and emergencies.
2. **Unusual occurrences.** OPERATING AUTHORITIES should include disturbance reports and reports of other unusual occurrences in their training programs.

C. Certification

[**Certification Specifications at:** https://www.nerc.net/exam/**]**

Standards

(1. to 032, R1)

1. **Positions requiring NERC-Certified SYSTEM OPERATORS**. An OPERATING AUTHORITY that maintains a control center(s) for the real-time operation of the interconnected BULK ELECTRIC SYSTEM, shall staff operating positions that meet both of the following criteria with NERC-Certified SYSTEM OPERATORS in accordance with the schedule in Standard 2:

- Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected BULK ELECTRIC SYSTEM, **and**
- Positions that are directly responsible for complying with *NERC Operating Policies*.

2. **Staffing Schedule**. Operating positions identified in Standard 1 shall be staffed according to the following schedule:

- After December 31, 1999, at least one NERC-Certified SYSTEM OPERATOR shall be on duty at all times, and
- After December 31, 2000, all of these positions shall be staffed with NERC-Certified SYSTEM OPERATORS at all times.

(Note: Exceptions are covered by wording from P8T2 Compliance Template Measures)

- **EXCEPTION** – While in training to become a NERC-Certified SYSTEM OPERATOR, an uncertified individual may work only in a non-independent position and must be under the direct authority of a NERC-Certified SYSTEM OPERATOR.

Note 1: Statements from Policies and related appendices that have been moved to Version 0 Standards have been highlighted and the new Version 0 location has been identified as: 1.0 moved to Version 0 Standard 001, Requirement 1, (Simplified as 1.0 to 001, R1). Un-highlighted statements have not been included in Version 0 Standards.
Note 2: In the Version 0 standards, policy statements have been changed to "active voice" wording, and entity titles have been changed to reflect the Functional Model. Other wording changes are intended to be clarification of meaning only.

Policy 9 – Reliability Coordinator Procedures

Version 2

Subsections

A. **Responsibilities – Authorization**
B. **Responsibilities – Delegation of Tasks**
C. **Common Tasks for Current-Day and Next-Day Operations**
D. **Next-Day Operations**
E. **Current-Day Operations**
F. **Emergency Operations**
G. **System Restoration**
H. **Coordination Agreements and Data Sharing**
I. **Facility**
J. **Staffing**

(The following requirement is included in 033, R1)

This requirement is from Policy 2, Requirement 2, quoted below:
"Every Region, subregion, or interregional coordinating group shall establish one or more RELIABILITY COORDINATORS to continuously assess transmission security and coordinate emergency operations among the CONTROL AREAS within the Subregion, Region, and across the Regional boundaries."

Introduction

This document contains the process and procedures that the NERC RELIABILITY COORDINATORS are expected to follow to ensure the operational reliability of the INTERCONNECTIONS. These include:

- Planning for next-day operations, including reliability analyses (such as pre- and post-CONTINGENCY thermal monitoring, system reserves, area reserves, reactive reserves, voltage limits, stability, etc.) and identifying special operating procedures that might be needed,

- Analyzing current day operating conditions, and

- Implementing procedures (local, INTERCONNECTION-wide, or other) to mitigate SYSTEM OPERATING LIMIT (SOL) and INTERCONNECTION RELIABILITY OPERATING LIMIT (IROL) violations on the transmission system. Regardless of the process, the RELIABILITY COORDINATOR shall ensure its CONTROL AREAS return their transmission system to within INTERCONNECTED RELIABILITY OPERATING LIMITS without delay, and no longer than 30 minutes[1]

RELIABILITY COORDINATORS shall have the capability to monitor their responsibilities with a WIDE AREA view perspective and calculate INTERCONNECTED RELIABILITY OPERATING LIMITS. WIDE AREA is described as the ability to monitor the complete RELIABILITY COORDINATOR AREA and may include critical flow and status information from adjacent RELIABILITY COORDINATOR AREAS as determined by detailed system studies. With this in mind it is likely that RELIABILITY COORDINATORS will discover IROL violations not normally seen by its TRANSMISSION OPERATING ENTITIES.

Terms

RELIABILITY COORDINATOR. The entity that is the highest level of authority who is responsible for the reliable operation of the BULK ELECTRIC SYSTEM, has the WIDE AREA view of the BULK ELECTRIC SYSTEM and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next day analysis and real time operations.

OPERATING AUTHORITY. An entity that:

1. Has ultimate accountability for a defined portion of the BULK ELECTRIC SYSTEM to meet one or more of three reliability objectives — generation/demand balance, transmission reliability, and/or emergency preparedness, and

2. Is accountable to NERC and its Regional Reliability Councils for complying with NERC and Regional Policies, and

3. Has the authority to control or direct the operation of generating resources, transmission facilities, or loads, to meet these Policies.

OPERATING AUTHORITIES include such entities as CONTROL AREAS, generation operators and TRANSMISSION OPERATING ENTITIES; they do not include RELIABILITY COORDINATORS.

RELIABILITY COORDINATOR AREA. That portion of the Bulk Electric System under the purview of the Reliability Coordinator.

OPERATING AUTHORITY AREA. That portion of the Bulk Electric System under the purview of the Operating Authority that is contained within a Reliability coordinator area.

BURDEN. Operation of the Bulk Electric System that violates or is expected to violate a SOL or IROL in the Interconnection or that violates any other NERC, Regional, or local operating reliability policies or standards.

WIDE AREA. The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnected Reliability Operating Limits.

[1] The 30-minute time period is not intended as a grace period for operating one CONTINGENCY away from instability, uncontrolled separation, or cascading outages. Some operating limit violations require mitigation much sooner.

CONTINGENCY. The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element. A Contingency also may include multiple components that are related by situations leading to simultaneous component outages.

SYSTEM OPERATING LIMIT (SOL). The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:

- Facility Ratings (Applicable pre- and post-CONTINGENCY equipment or facility ratings)
- Transient Stability Ratings (Applicable pre- and post-CONTINGENCY Stability Limits)
- Voltage Stability Ratings (Applicable pre- and post-CONTINGENCY Voltage Stability)
- System Voltage Limits (Applicable pre- and post-CONTINGENCY Voltage Limits)

INTERCONNECTION RELIABILITY OPERATING LIMIT (IROL). The value (such as MW, MVar, Amperes, Frequency or Volts) derived from, or a subset of the SYSTEM OPERATING LIMITS, which if exceeded, could expose a widespread area of the BULK ELECTRIC SYSTEM to instability, uncontrolled separation(s) or cascading outages.

A. Responsibilities – Authorization

Requirements

1. **RELIABILITY COORDINATOR responsibilities.** The RELIABILITY COORDINATOR is responsible for the reliable operation of its RELIABILITY COORDINATOR AREA within the BULK ELECTRIC SYSTEM in accordance with NERC, Regional and sub-Regional practices.

(1.1 TO PURPOSE 035)

1.1. The RELIABILITY COORDINATOR is responsible for having the WIDE AREA view, the operating tools, processes and procedures, including the authority, to prevent or mitigate emergency operating situations in both next-day analysis and during real-time conditions.

(1.2 to 033, R3)

1.2. The RELIABILITY COORDINATOR shall have clear decision-making authority to act and to direct actions to be taken by other OPERATING AUTHORITIES within its RELIABILITY COORDINATOR AREA to preserve the integrity and reliability of the BULK ELECTRIC SYSTEM. These actions shall be taken without delay, and no longer than 30 minutes[2]

(1.3 to 033, R4)

1.3. The RELIABILITY COORDINATOR shall not delegate its responsibilities to other OPERATING AUTHORITIES or entities.

(2. to 033, R9)

2. **Serving the interests of the RELIABILITY COORDINATOR AREA and the INTERCONNECTION.** The RELIABILITY COORDINATOR shall act in the interests of reliability for the overall RELIABILITY COORDINATOR AREA and its INTERCONNECTION before the interests of any other entity (CONTROL AREA, TRANSMISSION OPERATING ENTITY, PURCHASING-SELLING ENTITY, etc.).

(3. to 033, R8)

3. **Compliance with RELIABILITY COORDINATOR directives.** All OPERATING AUTHORITIES shall comply with RELIABILITY COORDINATOR directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances the OPERATING AUTHORITY must immediately inform the RELIABILITY COORDINATOR of the inability to perform the directive so that the RELIABILITY COORDINATOR may implement alternate remedial actions.

4. **Reliability Plan approval.** The NERC Operating Committee must approve the RELIABILITY COORDINATOR or Regional Reliability Plan.

[2] The 30-minute time period is not intended as a grace period for operating one CONTINGENCY away from instability, uncontrolled separation, or cascading outages. Some operating limit violations require mitigation much sooner.

B. Responsibilities – Delegation of Tasks

Requirements

(1. to 033, R4)

1. Delegating tasks. The RELIABILITY COORDINATOR may delegate tasks to other OPERATING AUTHORITIES and entities, but this delegation must be accompanied by formal operating agreements. The RELIABILITY COORDINATOR shall ensure that all delegated tasks are understood, communicated, and addressed by all OPERATING AUTHORITIES within its RELIABILITY COORDINATOR AREA.

(2. to 033, R5)

2. Designating delegation. The RELIABILITY COORDINATOR or Regional Reliability Plan must list all OPERATING AUTHORITIES and entities to which RELIABILITY COORDINATOR tasks have been delegated.

(3. to 033, R6)

3. Requirements for certified operators. OPERATING AUTHORITIES and entities must ensure that these delegated tasks are carried out by NERC-certified RELIABILITY COORDINATOR operators.

4. Auditing delegated tasks. Entities that accept delegation of RELIABILITY COORDINATOR tasks, may have these tasks audited under the NERC RELIABILITY COORDINATOR audit program.

C. Common Tasks for Next-Day and Current-Day Operations

Requirements

1. In all time frames RELIABILITY COORDINATORS are responsible for the following:

1.1. **Assessing CONTINGENCY situations**. The RELIABILITY COORDINATOR shall coordinate operations in regards to SOLS and IROLS for real time and next day operations for its RELIABILITY COORDINATOR AREA including thermal, voltage and stability related analysis. Assessments shall be conducted, up to and including next-day, at the CONTROL AREA level with any identified potential SOL violations reported to the RELIABILITY COORDINATOR. The RELIABILITY COORDINATOR is to ensure that its WIDE AREA view is modeled to ensure coordinated operations.

1.2. **Determining IROLS.** The RELIABILITY COORDINATOR shall determine IROLS based on local, regional and interregional studies. The RELIABILITY COORDINATOR must be aware that an IROL violation can be created during multiple, normally non-critical outage conditions and, as such, the RELIABILITY COORDINATOR must be knowledgeable of events that could lead to such an occurrence. The RELIABILITY COORDINATOR is responsible for disseminating this information within its RELIABILITY COORDINATOR AREA and to neighboring RELIABILITY COORDINATORS.

(1.3 to 038, R15)

1.3. **Assuring OPERATING AUTHORITIES shall not BURDEN others.** The RELIABILITY COORDINATOR shall ensure that all OPERATING AUTHORITIES will operate to prevent the likelihood that a disturbance, action, or non-action in its RELIABILITY COORDINATOR AREA will result in a SOL or IROL violation in another area of the INTERCONNECTION. Doing otherwise is considered a BURDEN that one OPERATING AUTHORITY places on another. In instances where there is a difference in derived limits, the BULK ELECTRIC SYSTEM shall always be operated by the RELIABILITY COORDINATOR and its OPERATING AUTHORITIES to the most limiting parameter.

1.4. **Operating under known conditions.** The RELIABILITY COORDINATORS shall ensure OPERATING AUTHORITIES always operate their OPERATING AUTHORITY AREA under known and studied conditions and also ensure they reassess and reposture their systems following CONTINGENCY events without delay, and no longer than 30 minutes[3], regardless of the number of CONTINGENCY events that occur or the status of their monitoring, operating and analysis tools.

(1.5 to 038, R16)

1.5. **Total Transfer Capability or Available Transfer Capability and transmission coordination.** The RELIABILITY COORDINATOR shall make known to OPERATING AUTHORITIES within its RELIABILITY COORDINATOR AREA, SOLs or IROLs within its

[3] The 30-minute time period is not intended as a grace period for operating one CONTINGENCY away from instability, uncontrolled separation, or cascading outages. Some operating limit violations require mitigation much sooner.

WIDE AREA view. The OPERATING AUTHORITY shall respect these SOLs or IROLs in accordance with filed tariffs and regional TTC/ATC calculation processes.

(1.6 to 038, R17)

1.6. Communications. The RELIABILITY COORDINATOR shall issue directives in a clear, concise, definitive manner. The RELIABILITY COORDINATOR shall receive a response from the person receiving the directive that repeats the information given. The RELIABILITY COORDINATOR shall acknowledge the statement as correct or repeat the original statement to resolve misunderstandings.

D. Next-Day Operations

Requirements

(1. to 037, R1)

1. **Performing reliability analysis and system studies.** The RELIABILITY COORDINATOR shall conduct next-day reliability analyses for its RELIABILITY COORDINATOR AREA to ensure that the BULK ELECTRIC SYSTEM can be operated reliably in anticipated normal and CONTINGENCY event conditions.

(1.1 to 037, R1)

1.1. **Contingency analysis.** The RELIABILITY COORDINATOR shall conduct CONTINGENCY analysis studies to identify potential interface and other SOL and IROL violations, including overloaded transmission lines and transformers, voltage and stability limits, etc.

(1.2 to 037, R2)

1.2. **Considering parallel flows.** The RELIABILITY COORDINATOR shall pay particular attention to parallel flows to ensure one RELIABILITY COORDINATOR AREA does not place an unacceptable or undue BURDEN on an adjacent RELIABILITY COORDINATOR AREA.

(2. to 037, R4)

2. **Sharing information.** Each OPERATING AUTHORITY in the RELIABILITY COORDINATOR AREA shall provide information required for system studies, such as critical facility status, load, generation, operating reserve projections, and known INTERCHANGE TRANSACTIONS. This information shall be available by 1200 Central Standard Time for the Eastern INTERCONNECTION, and 1200 Pacific Standard Time for the Western INTERCONNECTION.

3. **Developing action plans.** The RELIABILITY COORDINATOR shall, in conjunction with its OPERATING AUTHORITIES, develop action plans that may be required including reconfiguration of the transmission system, redispatching of generation, reduction or curtailment of INTERCHANGE TRANSACTIONS, or reducing load to return transmission loading to within acceptable SOLs or IROLs.

(4. to 037, R5)

4. **Sharing study results**. The RELIABILITY COORDINATOR shall share the results of its system studies, when conditions warrant or upon request, with other RELIABILITY COORDINATORS, and OPERATING AUTHORITIES within its RELIABILITY COORDINATION AREA. Study results shall be available no later than 1500 Central Standard Time for the Eastern INTERCONNECTION, and 1500 Pacific Standard Time for the Western INTERCONNECTION, unless circumstances warrant otherwise.

(5. to 037, R6)

5. Communication of results of next-day reliability analyses. Whenever conditions warrant, the RELIABILITY COORDINATOR shall initiate a conference call or other appropriate communications to address the results of its reliability analyses.

(6. to 037, R7)

6. Alerts. If the results of these studies indicate potential SOL or IROL violations, the RELIABILITY COORDINATORS shall issue the appropriate alerts via the Reliability Coordinator Information System (RCIS) and direct their OPERATING AUTHORITIES to take any necessary action the RELIABILITY COORDINATOR deems appropriate to address the potential SOL or IROL violation.

(7. to 037, R8)

7. Operating Authority Response. OPERATING AUTHORITIES shall comply with the directives of its RELIABILITY COORDINATOR based on the next day assessments in the same manner in which the OPERATING AUTHORITY would comply during real time operating events.

E. Current-Day Operations

(The following has been moved to 038, R7)
(Quote from Policy 1 section D, Time Control Standard)
"The Operating Reliability Subcommittee shall designate, on February 1st of each year, a RELIABILITY COORDINATOR to act as the Interconnection Time Monitor to monitor time error for each of the INTERCONNECTIONS and to issue time error correction orders."

Requirements

1. Monitoring and Coordination

(1.1 to 035, R1)

1.1. WIDE AREA view. The RELIABILITY COORDINATOR shall monitor all BULK ELECTRIC SYSTEM facilities within its RELIABILITY COORDINATOR AREA and adjacent RELIABILITY COORDINATOR AREAS as necessary to ensure that, at any time, regardless of prior planned or unplanned events, the RELIABILITY COORDINATOR is able to determine any potential SOL and IROL violations within its RELIABILITY COORDINATOR AREA. This responsibility may require RELIABILITY COORDINATORS to receive sub-transmission information not normally monitored by their Energy Management System to assist in IROL determination.

(1.1.1 TO 035, R2)

1.1.1. WIDE AREA view – coordination. When a neighboring RELIABILITY COORDINATOR is aware of an external operational concern, such as declining voltages, excessive reactive flows, or an IROL violation, the neighboring RELIABILITY COORDINATOR shall contact the RELIABILITY COORDINATOR in whose RELIABILITY COORDINATOR AREA the operational concern was observed. They shall coordinate any actions, including emergency assistance, required by the RELIABILITY COORDINATOR in mitigating the operational concern.

(1.2 TO 035, R3)

1.2. Facility status. The RELIABILITY COORDINATOR must know the status of all current critical facilities whose failure, degradation, or disconnection could result in an SOL or IROL violation. RELIABILITY COORDINATORS must also know the status of any facilities that may be required to assist area restoration objectives.

(1.3 through 1.3.10 to 038, R1)

1.3. Situational awareness. The RELIABILITY COORDINATOR shall be continuously aware of conditions within its RELIABILITY COORDINATOR AREA and include this information in its reliability assessments. To accomplish this objective the RELIABILITY COORDINATOR shall monitor its RELIABILITY COORDINATOR AREA parameters, including but not limited to the following:

1.3.1. Current status of BULK ELECTRIC SYSTEM elements (transmission or generation including critical auxiliaries such as Automatic Voltage Regulators and Special Protection Systems and system loading

1.3.2. Current pre-CONTINGENCY element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate an SOL or IROL violation including the plan's viability and scope

1.3.3. Current post- CONTINGENCY element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate an SOL or IROL including the plan's viability and scope

1.3.4. System real and reactive reserves (actual versus required)

1.3.5. Capacity and energy adequacy conditions

1.3.6. Current ACE for all its CONTROL AREAS

1.3.7. Current local or TLR procedures in effect

1.3.8. Planned generation dispatches

1.3.9. Planned transmission or generation outages

1.3.10. CONTINGENCY events

1.4. **BULK ELECTRIC SYSTEM monitoring**. The RELIABILITY COORDINATOR shall monitor BULK ELECTRIC SYSTEM parameters that may have significant impacts upon the RELIABILITY COORDINATOR AREA and with neighboring RELIABILITY COORDINATOR AREAS with respect to:

(1.4.1 TO 038, R2)

1.4.1. **INTERCHANGE TRANSACTION information.** The RELIABILITY COORDINATOR shall be aware of all INTERCHANGE TRANSACTIONS that wheel-through, source, or sink in its RELIABILITY COORDINATOR AREA and make that INTERCHANGE TRANSACTION information available to all RELIABILITY COORDINATORS in the INTERCONNECTION. (Note: This requirement is satisfied by the Interchange Distribution Calculator and E-Tag process for the Eastern INTERCONNECTION.)

(1.4.2 TO 038 R3)

1.4.2. **Pending INTERCHANGE SCHEDULES to identify potential flow impacts.** As portions of the transmission system approach or exceed SOLS or IROLS, the RELIABILITY COORDINATOR shall work with the OPERATING AUTHORITIES to evaluate and assess any additional INTERCHANGE SCHEDULES that would violate those limits. If the potential or actual IROL violation cannot be avoided through proactive intervention, the RELIABILITY COORDINATOR shall initiate control actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes[4]. All resources, including load shedding shall be available to the RELIABILITY COORDINATOR in addressing a potential or actual SOL or IROL violation.

[4] The 30-minute time period is not intended as a grace period for operating one CONTINGENCY away from instability, uncontrolled separation, or cascading outages. Some operating limit violations require mitigation much sooner.

(1.4.3 to 038 R4)

1.4.3. Availability or shortage of OPERATING RESERVES needed to maintain reliability. The RELIABILITY COORDINATOR shall monitor CONTROL AREA parameters to ensure that the required amount of OPERATING RESERVES are provided and available as required to meet NERC Control Performance Standard and Disturbance Control Standards requirements. If necessary, the RELIABILITY COORDINATOR shall direct the CONTROL AREAS in the RELIABILITY COORDINATOR AREA to arrange for assistance from neighboring areas (CONTROL AREAS, REGIONS, etc.). The RELIABILITY COORDINATOR shall issue ENERGY EMERGENCY Alerts, as needed, and at the request of LOAD SERVING ENTITIES.

(1.4.4 to 038, R5)

1.4.4. Actual flows versus limits. The RELIABILITY COORDINATOR shall identify the cause of the potential or actual IROL violations and initiate the control action or emergency procedure to relieve the potential or actual IROL violation without delay, and no longer than 30 minutes[5]. All resources, including load shedding, shall be available to the RELIABILITY COORDINATOR in addressing a SOL or IROL violation.

1.4.5. Time error correction and GMD notification. (This part to 038, R6) The RELIABILITY COORDINATOR will communicate start and end times for time error corrections to the CONTROL AREAS within its RELIABILITY AREA.

(This part to 038, R8) The RELIABILITY COORDINATOR will ensure all CONTROL AREAS are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.

(1.4.6 TO 038, R9)

1.4.6. RELIABILITY COORDINATOR coordination with other Regions. The RELIABILITY COORDINATOR shall participate in NERC Hotline discussions, assist in the assessment of reliability of the Regions and the overall interconnected system, and coordinate actions in anticipated or actual emergency situations. The RELIABILITY COORDINATOR will disseminate information within its RELIABILITY COORDINATOR AREA.

(1.4.7 TO 038, R10)

1.4.7. System frequency and resolution of significant frequency errors, deviations, and real-time trends. The RELIABILITY COORDINATOR shall monitor system frequency and its CONTROL AREAS' performance and direct any necessary rebalancing to return to CPS and DCS compliance. All resources, including firm load shedding, shall be utilized as directed by a RELIABILITY COORDINATOR to relieve the emergent condition.

(1.4.8 TO 038, R11)

[5] The 30-minute time period is not intended as a grace period for operating one CONTINGENCY away from instability, uncontrolled separation, or cascading outages. Some operating limit violations require mitigation much sooner.

1.4.8. **Sharing with other RELIABILITY COORDINATORS any information regarding potential, expected, or actual critical operating conditions that could negatively impact other RELIABILITY COORDINATOR AREAS.** The RELIABILITY COORDINATOR shall coordinate with other RELIABILITY COORDINATORS and CONTROL AREAS, as needed, to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS or DCS violations. This would include coordination of pending generation and transmission maintenance outages in both the real time and next day reliability analysis timeframes.

(1.4.9 TO 038, R12)

1.4.9. **Availability or shortage of Interconnected Operations Services required (in applicable RELIABILITY COORDINATOR AREAS).** As necessary, the RELIABILITY COORDINATOR shall assist the CONTROL AREAS in its RELIABILITY AREA in arranging for assistance from neighboring RELIABILITY COORDINATOR AREAS or CONTROL AREAS.

(1.4.10 TO 038, R13)

1.4.10. **Individual CONTROL AREA or RELIABILITY COORDINATOR AREA ACE (in applicable RELIABILITY AREAS).** The RELIABILITY COORDINATOR will identify sources of large AREA CONTROL ERRORS that may be contributing to frequency, time error, or inadvertent interchange and will discuss corrective actions with the appropriate CONTROL AREA operator. If a frequency, time error, or inadvertent problem occurs outside of the RELIABILITY COORDINATOR AREA, the RELIABILITY COORDINATOR will initiate a NERC Hotline call to discuss the frequency, time error, or inadvertent interchange with other RELIABILITY COORDINATORS. The RELIABILITY COORDINATOR shall direct its CONTROL AREAS to comply with CPS and DCS as indicated in section 1.4.7 above.

(1.4.11 TO 038, R14)

1.4.11. **Use of Special Protection Systems (in applicable RELIABILITY COORDINATOR AREAS).** Whenever a Special Protection System that may have an inter-CONTROL AREA or inter-RELIABILITY COORDINATOR AREA impact (e.g. could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the RELIABILITY COORDINATORS shall be aware of the impact of the operation on inter-Area flows. The RELIABILITY COORDINATOR shall be kept informed of the status of the Special Protection System including any degradation or potential failure to operate as expected.

(1.5 to 038, R18)

1.5. **Communication with RELIABILITY COORDINATORS of potential problems.** The RELIABILITY COORDINATOR who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its RELIABILITY COORDINATOR AREA shall issue an alert to all CONTROL AREAS and TRANSMISSION OPERATING ENTITIES in its RELIABILITY AREA, and all RELIABILITY COORDINATORS within the INTERCONNECTION via the Reliability Coordinator Information System without delay. The RELIABILITY COORDINATOR will disseminate this information to its OPERATING AUTHORITIES.

(1.6 to 038, R19)

1.6. **Provide other coordination services as appropriate and as requested by the CONTROL AREAS within its RELIABILITY COORDINATOR AREA and neighboring RELIABILITY COORDINATOR AREAS.** The RELIABILITY COORDINATOR shall confirm reliability assessment results and determine the effects within its own and adjacent RELIABILITY COORDINATOR AREAS. This action includes discussing options to mitigate potential or actual SOL or IROL violations and taking actions as necessary as to always act in the best interests of the INTERCONNECTION at all times.

F. Emergency Operations

Requirements

1. **Mitigating SOL and IROL violations.** Regardless of the process it uses, the RELIABILITY COORDINATOR shall direct its OPERATING AUTHORITIES to return the transmission system to within the IROL as soon as possible, but no longer than 30 minutes. With this in mind, RELIABILITY COORDINATORS and their OPERATING AUTHORITIES must be aware that Transmission Loading Relief (TLR) procedures may not be able to mitigate the SOL or IROL violation in a timely fashion. Under these circumstances other actions such as reconfiguration, redispatch or load shedding may be necessary until the relief requested by the TLR process is achieved. In these instances the RELIABILITY COORDINATOR shall direct and OPERATING AUTHORITIES shall comply with the more timely requests.

2. **Implementing emergency procedures.** If the RELIABILITY COORDINATOR deems that IROL violations are imminent, the RELIABILITY COORDINATOR shall have the authority and obligation to immediately direct its OPERATING AUTHORITIES to redispatch generation, reconfigure transmission, manage INTERCHANGE TRANSACTIONS, or reduce system demand to mitigate the IROL violation until INTERCHANGE TRANSACTIONS can be reduced utilizing a transmission loading relief procedure, or other procedures, to return the system to a reliable state. The RELIABILITY COORDINATOR shall coordinate these emergency procedures with other RELIABILITY COORDINATORS as needed. [See also Policy 5, "Emergency Operations"]

3. **Implementing relief procedures.** If transmission loading progresses or is projected to violate a SOL or IROL, the RELIABILITY COORDINATOR will perform the following procedures as necessary:

   (3.1 to 039, R2)

   3.1. Selecting transmission loading relief procedure. The RELIABILITY COORDINATOR experiencing a potential or actual SOL or IROL violation on the transmission system within its RELIABILITY COORDINATOR AREA shall, at its discretion, select from either a "local" (Regional, Interregional, or subregional) transmission loading relief procedure or an INTERCONNECTION-wide procedure, such as those listed in Appendix 9C1, 9C2, or 9C3

   (3.2 to 039, R3)

   3.2. Using local transmission loading relief procedure. The RELIABILITY COORDINATOR may use local transmission loading relief or congestion management procedures, provided the TRANSMISSION OPERATING ENTITY experiencing the potential or actual SOL or IROL violation is a party to those procedures.

   (3.3 to 039, R4)

   3.3. Using a local procedure with an INTERCONNECTION-wide procedure. A RELIABILITY COORDINATOR may implement a local transmission loading relief or congestion management procedure simultaneously with an INTERCONNECTION-wide procedure. However, the RELIABILITY COORDINATOR is obligated to follow the curtailments as directed by the INTERCONNECTION-wide procedure. If the RELIABILITY COORDINATOR desires to use a local procedure *as a substitute* for curtailments as directed by the

INTERCONNECTION-wide procedure, it may do so only if such use is approved by the NERC Operating Reliability Subcommittee and Operating Committee.

(3.4 to 039, R5)

3.4. **Complying with procedures.** When implemented, all RELIABILITY COORDINATORS shall comply with the provisions of the INTERCONNECTION-wide procedure. This may include action by RELIABILITY COORDINATORS in other INTERCONNECTIONS to, for example, curtail an INTERCHANGE TRANSACTION that crosses an INTERCONNECTION boundary.

(3.5 to 039, R6)

3.5. **Complying with interchange policies.** During the implementation of relief procedures, and up to the point that emergency action is necessary, RELIABILITY COORDINATORS and OPERATING AUTHORITIES shall comply with the Requirements of Policy 3, Section C, "Interchange Schedule Standards."

(4. to 039, R7

4. **Determining causes of Interconnection frequency error.** Any RELIABILITY COORDINATOR noticing an INTERCONNECTION frequency error in excess of 0.03 Hz (Eastern INTERCONNECTION) or 0.05 Hz (Western and ERCOT INTERCONNECTIONS) for more than 20 minutes shall initiate a NERC Hotline conference call, or notification via the Reliability Coordinator Information System, to determine the CONTROL AREA(S) with the energy emergency or control problem.

4.1. If a RELIABILITY COORDINATOR determines that one or more of its CONTROL AREAS is contributing to the frequency error, the RELIABILITY COORDINATOR shall direct those CONTROL AREA(S) to immediately comply with CPS and DCS requirements by using all resources available to it, including load shedding. The CONTROL AREA(S) shall comply with the RELIABILITY COORDINATOR request.

5. **Authority to provide emergency assistance.** The RELIABILITY COORDINATOR shall have the authority to take or direct whatever action is needed, including load shedding, to mitigate an energy emergency within its RELIABILITY COORDINATOR AREA. OPERATING AUTHORITIES shall ensure the directive of the RELIABILITY COORDINATOR is implemented. RELIABILITY COORDINATORS shall provide assistance to other RELIABILITY COORDINATORS experiencing an energy emergency in accordance with Appendix 5C, Subsection A, "Energy Emergency Alerts."

(6. to 020, R6)

6. **Communication of Energy Emergencies.** The RELIABILITY COORDINATOR that is experiencing a potential or actual Energy Emergency within any CONTROL AREA, RESERVE-SHARING GROUP, or LOAD-SERVING ENTITY within its RELIABILITY COORDINATOR AREA shall initiate an Energy Emergency Alert as detailed in Appendix 5C, Subsection A – "Energy Emergency Alert Levels." The RELIABILITY COORDINATOR shall also act to mitigate the emergency condition, including a request for emergency assistance if required.

G. System Restoration

Requirements

(1. to 040, R1 and R2)

1. **Operating Authority restoration plans.** (This part to 040, R1)The RELIABILITY COORDINATOR shall be aware of each OPERATING AUTHORITY'S restoration plan in its RELIABILITY COORDINATOR AREA in accordance with NERC and Regional requirements.

   (This part to 040, R2) During system restoration, the RELIABILITY COORDINATOR shall monitor restoration progress and coordinate any needed assistance.

(2. to 040, R3)

2. **Reliability Coordinator restoration plan.** The RELIABILITY COORDINATOR shall have a RELIABILITY COORDINATOR AREA restoration plan that provides coordination between individual OPERATING AUTHORITY restoration plans and that ensures reliability is maintained during system restoration events.

(3. to 040, R4)

3. **Reliability Coordinator is the primary contact.** The RELIABILITY COORDINATOR shall serve as the primary contact for disseminating information regarding restoration to neighboring RELIABILITY COORDINATORS and OPERATING AUTHORITIES not immediately involved in restoration.

(4. to 040, R5)

4. **Re-synchronizing islands.** RELIABILITY COORDINATORS shall approve, communicate, and coordinate the re-synchronizing of major system islands or synchronizing points so as not to BURDEN adjacent OPERATING AUTHORITIES or RELIABILITY COORDINATOR AREAS.

   (4.1 to 040, R6)

   4.1. **Reestablishing normal operations.** The RELIABILITY COORDINATOR shall take actions to restore normal operations once an operating emergency has been mitigated in accordance with its restoration plan.

H. Coordination Agreements and Data Sharing

Requirements

(1. to 033, R7)

1. Coordination agreements. The RELIABILITY COORDINATOR must have clear, comprehensive coordination agreements with adjacent RELIABILITY COORDINATORS to ensure that SOL or IROL violation mitigation requiring actions in adjacent RELIABILITY COORDINATOR AREAS are coordinated.

(2. to 034, R2)

2. Data requirements. The RELIABILITY COORDINATOR shall determine the data requirements to support its reliability coordination tasks and shall request such data from its OPERATING AUTHORITIES or adjacent RELIABILITY COORDINATORS, in accordance with the provisions of Policy 4, "System Coordination."

(3. to 034, R3)

3. Data exchange. The RELIABILITY COORDINATOR or its OPERATING AUTHORITIES shall provide, or arrange provisions for, data exchange to other RELIABILITY COORDINATORS or OPERATING AUTHORITIES via the Interregional Security Network or RCIS network as required by NERC policy.

I. Facility

Requirements

1. RELIABILITY COORDINATORS shall have the facilities to perform their responsibilities, including:

(1.1 to 034, R1)

1.1. **Communications.** RELIABILITY COORDINATORS shall have adequate communications (voice and data links) to appropriate entities within its RELIABILITY COORDINATOR AREA, which are staffed and available to act in addressing a real time emergency condition.

(1.2 to 034, R4)

1.2. **Timely dissemination of information.** This includes multi directional capabilities between an OPERATING AUTHORITY and its RELIABILITY COORDINATOR and also from a RELIABILITY COORDINATOR to its neighboring RELIABILITY COORDINATOR(S) for both voice and data exchange as required to meet reliability needs of the INTERCONNECTION.

(1.3 to 034, R5)

1.3. **Monitoring capability.** Detailed real-time monitoring capability of the RELIABILITY COORDINATOR AREA and sufficient monitoring capability of the surrounding RELIABILITY COORDINATOR AREAS to ensure that potential or actual SOL or IROL violations are identified. Monitoring systems shall provide information that can be easily understood and interpreted by the RELIABILITY COORDINATOR, giving particular emphasis to alarm management and awareness systems, automated data transfers, synchronized information systems, over a redundant and highly reliable infrastructure.

(1.3.1 to 034, R6)

1.3.1. RELIABILITY COORDINATORS shall monitor BULK ELECTRIC SYSTEM elements (generators, transmission lines, busses, transformers, breakers, etc.) that could result in SOL or IROL violations within its RELIABILITY COORDINATOR AREA. This monitoring overview shall include both real and reactive power system flows, and OPERATING RESERVES, and the status of BULK ELECTRIC SYSTEM elements that are or could be critical to SOLs and IROLs and system restoration requirements within its RELIABILITY COORDINATOR AREA.

1.4. **Study and analysis tools.**

(1.4.1 to 034, R7)

1.4.1. **Analysis tools.** The RELIABILITY COORDINATOR shall have adequate analysis tools such as State Estimation, pre- and post-CONTINGENCY analysis capabilities (thermal, stability, and voltage) and WIDE AREA overview displays.

(1.4.2 to 034, R8)

1.4.2. Continuous monitoring of RELIABILITY COORDINATOR AREA. The RELIABILITY COORDINATOR shall continuously monitor its RELIABILITY COORDINATOR AREA. This includes the provisions for backup facilities that shall be exercised if the main monitoring system is unavailable. Backup provisions shall ensure SOL and IROL monitoring and derivations continues if the main monitoring system is unavailable.

(1.4.3 to 034, R9)

1.4.3. Availability of analysis capabilities. RELIABILITY COORDINATOR analysis tools shall be under the control of the RELIABILITY COORDINATOR, including approvals for planned maintenance. Procedures shall be in place to mitigate the affects of analysis tool outages.

J. Staffing

Requirements

The minimum training requirements will be moved to Policy 8 upon its next revision.

1. RELIABILITY COORDINATORS shall have adequate staff and facilities:

(1.1 to 036, R1)

1.1. **Staffing and training**. The RELIABILITY COORDINATOR shall be staffed with adequately trained and NERC-Certified RELIABILITY COORDINATOR operators, 24 hours/day, seven days/week. The RELIABILITY COORDINATOR must have detailed knowledge of its RELIABILITY COORDINATOR AREA, its facilities, and associated OPERATING AUTHORITIES' processes including emergency procedures and restoration objectives. Training for RELIABILITY COORDINATOR operators shall meet or exceed a minimum of 5 days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.

(1.2 to 036, R2, R3 and R4)

1.2. **Knowledge of the RELIABILITY COORDINATOR AREA**. (This part to 036, R2) The RELIABILITY COORDINATOR shall have a comprehensive understanding of its RELIABILITY COORDINATOR AREA and interaction with neighboring RELIABILITY COORDINATOR AREAS.

(This part to 036, R3) Although OPERATING AUTHORITIES have the most detailed knowledge of their particular systems, the RELIABILITY COORDINATOR must have an extensive understanding of the OPERATING AUTHORITIES within its RELIABILITY COORDINATOR AREA, such as staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities and restrictions.

(This part to 036, R4) The RELIABILITY COORDINATOR shall place particular attention on SOLs and IROLs and intertie facility limits. The RELIABILITY COORDINATOR shall ensure protocols are in place to allow the RELIABILITY COORDINATOR to have the best available information at all times.

1.3. **Standards of Conduct**. The entity responsible for the RELIABILITY COORDINATOR function shall sign and adhere to the NERC RELIABILITY COORDINATOR Standards of Conduct.

Attachment B

NERC Performance Standards Reference Document

Performance Standards Reference Document

Version 3

This reference document is intended to provide the reader with a better understanding of the balancing-related standards. While the information can provide clarity on potential ways to demonstrate compliance, the document should not be used by compliance staff as a benchmark to measure compliance or create new obligations not found in the standards. Should any difference or conflict be found between this document and the standards, the standards take precedence.

Subsections

A. General

[Area Interchange Error Training Document – ACE Equation]

This document provides instructions for calculating the control performance of the balancing authority (BA) and instructions and forms to complete the required surveys. It is intended to serve industry participants as a "how to" guide for application and interpretation of the performance standards.

The BA's Area Control Error (ACE) is the basis for the calculation of control parameters used to evaluate control performance. ACE is used to determine a BA's control performance with respect to the BA's impact on system frequency. The value of ACE to be used throughout the calculation of control parameters is directed by standards to reflect its actual value and exclude short excursions due to transient telemetering problems or other influences such as control algorithm actions. Erroneous readings such as "spikes" due to telemetering error or other false influences should be excluded from the calculations. However, the computations should include ALL of the non-erroneous intervals (i.e., do not exclude intervals that contain disturbance conditions). This ACE is defined as net actual interchange less net scheduled interchange less frequency bias contribution and meter error. It does not include offsets (e.g., unilateral inadvertent payback, WECC's automatic time error correction, etc.).

These measurements of control performance apply to all conditions (i.e., both normal and disturbance conditions). The BA is required to continuously monitor its control performance and report its compliance results at the end of each month.

Targeted Frequency Bounds. The targeted frequency bounds, epsilon 1 ($\in_1$) and epsilon 10 ($\in_{10}$), are based on historic measured frequency error. These bounds, typically in millihertz (mHz), embody the targeted frequency characteristics used for developing the Control Performance Standard. Each Interconnection is assigned its own frequency bounds.

The Targeted Frequency Bound for an Interconnection is computed as follows:

1. The NERC Resources Subcommittee (RS) defines a desired frequency profile.
2. The NERC RS collects frequency data from designated providers within each Interconnection. The frequency bounds are the RMS of the one- and ten-clock-minute averages of the frequency error (deviation) from schedule. These values are derived from data samples over a given year. The NERC RS calculates and then sets the targeted

frequency bounds, $\in_1$ and $\in_{10}$, to recognize the desired performance profile of frequency for each Interconnection.

Compliance for BAs. A BA that does not comply with CPS is not providing its required regulation services.

1. If a BA does not comply with the CPS, the BA is not permitted to provide regulation or other services related to control performance for any other BA(s) or other entities. Those services are to be determined by the NERC RS.
2. A BA failing to comply is directed by the standard to take immediate corrective action and achieve compliance within three months. If necessary, a BA is directed by the standard to buy sufficient supplemental regulation to achieve compliance.

Compliance for BAs Providing Regulation. A BA is not permitted to provide regulation or other services related to control performance (as determined by the NERC Resources Subcommittee) for (an)other BA(s) or other entities external to that BA, if the former BA does not comply with the CPS.

Compliance for BAs Participating in Supplemental Regulation. A BA providing or receiving supplemental regulation will continue to be evaluated on the characteristics of its own ACE with the supplemental regulation service included. The compliance calculations for each of the affected BAs will not change.

Compliance for BAs Participating in Overlap Regulation.

BAs Providing Overlap Regulation. A BA *providing* overlap regulation is to continue to be evaluated on the characteristics of the combined areas' ACE. The provider BA must calculate and use the sum of the frequency bias characteristics of itself and the BA for which it is providing the overlap regulation. Frequency bias minimums apply to each BA individually in these cases.

BAs Receiving Overlap Regulation. A BA *receiving* overlap regulation service is not to have its control performance evaluated.

B. Control Performance Standard 1, CPS1

[Area Interchange Error Training Document – ACE Equation]

CPS1 provides the BA with a frequency-sensitive evaluation of how well its demand requirements were met. The measure is not designed to be a visual indicator that an operator would use to control system generation, nor is it designed to address the issue of unscheduled power flows, or control of inadvertent interchange.

Metrics.

Over a given period, the average of the clock-minute averages of a BA's [ACE divided by ten times its bias] times the corresponding clock-minute averages of the Interconnection's frequency error is to be less than or equal to a constant (epsilon 1 squared, the constant on the right-hand side of the following inequality):

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right] \leq \in_1^2 \qquad or \qquad \frac{AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right]}{\in_1^2} \leq 1$$

where: **ACE_i** is the clock-minute average of ACE (as ACE is defined in Section A) and **B_i** is the frequency bias of the BA. For those areas with variable bias, an accumulation of $ACE/(–10B_i)$ is made through the AGC cycles of a minute, and the averaged value at the end of the minute should be saved as the clock-minute value of $ACE_i/(–10B_i)$,

$\in_1$ in Hz, is a constant derived from the targeted frequency bound. It is the targeted RMS of one-minute average frequency error from a schedule based on frequency performance over an averaging period of a year. The bound is the same for every BA within an Interconnection.

ΔF_1 (delta F sub one) in Hz, is the clock-minute average of frequency error from schedule, $\Delta F = F_a – F_s$, where F_a is the actual (measured) frequency and F_s is scheduled frequency for the Interconnection.

i is representative of the individual BA,

Period is defined as:

a) one year for BA evaluation
b) one month for reporting and Resources Subcommittee review

Compliance.

The fundamental requirement for CPS1 is that performance, as measured by percentage compliance, must be at least 100%.

It is possible for CPS1 percentage compliance to vary from –infinity to +infinity, depending on delta F and ACE magnitudes.

Control Compliance Rating = Pass if CPS1 ≥ 100%

Control Compliance Rating = Fail if CPS1 < 100%

CPS1 begins with a fundamental calculation called the compliance factor (CF). Its basic building block (called CF', or CF prime to distinguish it from CF as used later) is the quantity defined below, which essentially converts ACE to a form of frequency which can be compared with interconnection epsilon(s).

$$CF' = \left[\left(\frac{ACE}{-10B}\right) * \Delta F\right] \text{ Hz}^2$$

Note that as written above this quantity is an instantaneous value, no averaging involved.

CPS1 uses a 1-minute average base calculation, so CF' becomes

$$CF'_{\text{clock-minute}} = \left[\left(\frac{ACE}{-10B}\right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}}\right] \text{ Hz}^2$$

Note the units of this calculation are in terms of frequency squared. This is important in the calculations to follow, as comparison is made to epsilon squared to determine compliance.

The compliance factor, CF, is derived from CF' by dividing by epsilon squared:

$$CF = \frac{CF'}{(\in_1)^2}$$

CF is a (dimensionless) ratio that defines whether a BA's contribution to frequency deviation "noise" is greater than or less than the amount allowed. A value of 1 means exactly the amount of allowed frequency deviation-coincident "noise" has been contributed by the BA. Less than 1 means a "quieter" than required ACE characteristic. Negative means the BA is actually anticoincident with frequency deviation; generally a good thing as long as ACE magnitude is kept in check and the BA is not seriously over-controlling.

CPS1 then converts CF to a compliance percentage as follows:

CPS1% = (2 - *CF*) * 100%

This calculation is for any time interval. For compliance purposes, CPS1 percentage is calculated over the most recent 12 months (the month of the report plus the most recent 11 consecutive prior months). Epsilon can change, but since CPS1 is reported monthly, and epsilon would normally not be changed except on a month boundary, it is valid to calculate the monthly and the running 12-month CPS1 compliance as follows:

$$\mathbf{CPS1\%_{month} = (2 - CF_{month}) * 100\%}$$

where

$$CF_{\text{month}} = \frac{CF'_{\text{month}}}{(\in_1)^2} \qquad \text{and} \qquad CF'_{\text{month}} = \frac{\sum_{\text{1 min. periods in month}} (CF_{\text{clock-minute}})}{\left[n_{\text{1min. periods in month}}\right]}$$

$$\mathbf{CPS1\%_{12\text{-}month} = (2 - CF_{12\text{-}month})}$$

where

$$CF_{12-\text{month}} = \frac{\sum_{m=1}^{12}\left[CF_{\text{month}} \times n_{\text{1min. periods in month m}}\right]}{\sum_{m=1}^{12} n_{\text{1min. periods in month m}}}$$

"$n_{\text{1 min. periods in month m}}$" means the number of valid periods in the month (m), as described later herein.

The reason for the 12-month calculation (running 12-month compliance) being different is to allow for possible changes to epsilon 1. It would be undesirable to retroactively change previous months' measured performance by using a different epsilon than was in effect for them orginally. Also note that compliance percentages can be calculated for other time periods (month, day, shift hours, etc.) by replacing $CF_{\text{12-month}}$ in the above formula with the appropriate CF value.

Clock-minute average calculations.

A clock-minute average is the average of the reporting BA's valid measured variable (i.e., for ACE and for frequency error, as well as for the BA's frequency bias, as defined above) for each valid sample during a given clock minute.

$$\left(\frac{\text{ACE}}{-10\text{B}}\right)_{\text{clock-minute}} = \frac{\sum_{\text{samples in clock-minute}}\left[\frac{\text{ACE}}{-10\text{B}}\right]}{n_{\text{samples in clock-minute}}}$$

or, for a BA with constant Bias

$$\left(\frac{ACE}{-10B}\right)_{\text{clock-minute}} = \frac{\left(\frac{\left[\sum_{\text{samples in clock-minute}} ACE\right]}{n_{\text{samples in clock-minute}}}\right)}{\text{-10B}}$$

and

$$\Delta F_{\text{clock-minute}} = \frac{\sum_{\text{samples in clock-minute}} \Delta F}{n_{\text{samples in clock-minute}}}$$

The BA's clock-minute Compliance Factor (CF) becomes:

$$CF_{\text{clock-minute}} = \left[\left(\frac{ACE}{-10B}\right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}}\right]$$

Accumulated Averages.

The reporting entity can calculate and store compliance factors for a number of different reporting / analysis intervals. These factors can be used to calculate a CPS1 percentage for any desired time interval for any purpose desired.

for a single hour:
$$CF_{\text{clock-hour}} = \frac{\left[\sum_{\text{valid clock-minute averages in hour}} CF_{\text{clock-minute}}\right]}{n_{\text{valid clock-minute averages in hour}}}$$

for a month:
$$CF_{\text{month}} = \frac{\sum_{\text{hours-in-month}} [(CF_{\text{clock-hour}})(n_{\text{valid clock-minute averages in hour}})]}{\sum_{\text{hours-in month}} [n_{\text{valid clock-minute averages in hour}}]}$$

for (running) 12 months:
$$CF_{\text{12-month}} = \frac{\sum_{1}^{12} (CF_{\text{month}})(n_{\text{valid clock-minute averages in month}})]}{\sum_{1}^{12} [n_{\text{valid clock-minute averages in month}}]}$$

Interruptions in Data.

In order to ensure that the average ACE and Frequency Deviation calculated for any one-minute interval is representative of that one-minute interval, it is necessary that at least 50% of both ACE and Frequency Deviation sample pairs during that one-minute interval be present. The data pairs within a one-minute period need not be contiguous, but ACE and frequency data pairs must be simultaneous. Should an interruption in the recording of ACE or Frequency Deviation due to uncontrollable causes result in a one-minute interval not containing at least 50% of sample pairs of both ACE and Frequency Deviation, that one-minute interval is excluded from the calculation of CPS1.

Examples

Below is an example of the calculations required for CPS1 monitoring and compliance. The example starts with the first hour of the first day of a month through to the end of the month, and the BA bias, B = –60 MW/0.1 Hz.

On Day 1, at the beginning of HE 0100, the area must calculate $CF'_{\text{clock-minute}}$ by multiplying the clock-minute average ACE (divided by ten times the area's bias) by the clock-minute average frequency error from schedule. Subsequent products are calculated for the remaining clock-minutes of the hour.

HE 0100:		***Minute 1***	***Minute 2***	**...**	***Minute 60***	***Sum***	***CF'**$_{clock-hour}$* ***= Σ(CF')/n***
ACE	MW	-20	-10		-40		
ACE/-10B	Hz	-20/-10(-60) = .0333332	.0166667	...	.06666667		
ΔF	Hz	0.005	-0.005	...	0.005		
CF' = (ACE/-10B) x ΔF	Hz^2	-0.000167	0.000083	...	-0.000333	0.00525	0.000088 or 88 mHz^2
n = (# of 1-min averages)		1	1		1	60	

Note that n (# of 1-minute sample averages) is based on the number of valid samples over the hour. Since CPS1 requires 1-minute averages of ACE and frequency error (and there were no data anomalies in this hour), n = 60. The procedure shown above is repeated for each of the 24 hourly periods of each day. As the days of the month continue, the 24-hour period $CF'_{\text{clock-hour average-month}}$ values are averaged as shown below: At the end of the month, a CF'_{month} can be calculated.

A rolling $CF_{12\text{-month}}$

Hour		***Day 1***	***Day 2***	***...***	***Day 31***	***Sum***	***$CF'_{\text{clock-hour average-month}}$ = [Σ(CF' x n)]/Σ(n) mHz^2***
HE 0100	$CF'_{\text{clock-hour}}$	87.5	93.5	...	92.0		90.5
	n (# of averages)	60	59		57	1842	
	$CF'_{\text{clock-hour}}$ x n	5250	5516.5		5244	166,742	
HE 0200	$CF'_{\text{clock-hour}}$	90.0	85.0	...	89.5		87.5
	n	58	60		60	1830	
	$CF'_{\text{clock-hour}}$ x n	5220	5100		5370	160,170	
...	...	...	...	...	...		...
HE 2400	$CF'_{\text{clock-hour}}$	89.0	92.0	...	89.0		89.5
	n	60	59		59	1830	
	$CF'_{\text{clock-hour}}$ x n	5340	5428		5251	163,787	
		Total n				44,208	
		Total $CF'_{\text{clock-hour average-month}}$ x n				3,930,888	
		CF'_{month} =				88.9 mHz^2	
		Σ($CF'_{\text{clock-hour average-month}}$ x n)/ Σ (n)					

$CF_{12\text{-month}}$ can be calculated using the CF_{month} values.

	Month				***Year***	***Year***
	1	2	...	12	Sum	$CF'_{12\text{-month}}$
CF'_{month}	88.9	93.3	...	91.7		[Σ(CF'_{month} X n)/Σ(n)] =
n	44,208	42,072		42,875	515,030	**91.3 mHz^2**
CF'_{month} X n	3,930,888	3,925,345		3,931,655	47,022,239	

Assuming this interconnection has an ε_1 of 10 mHz, then the CPS1 compliance percentage would be calculated as follows:

$$\mathbf{CF} = CF'_{12\text{-month}} / (\varepsilon_1)^2 = 91.3\ \text{mHz}^2 / (10)^2\ \text{mHz}^2 = 91.3 / 100 = \mathbf{.913}$$

$$\mathbf{CPS1\ \%} = (2 - CF) \times 100\% = (2 - .913) \times 100\% = (1.087) \times 100\% = \mathbf{108.7\%}$$

which is a "passing" grade (12-month CPS1 must be at least 100%)

Surveys.

Performance Standard surveys are conducted monthly to analyze and demonstrate each BA's level of compliance with the Control Performance Standards. Completed surveys must be provided each month, to the Resources Subcommittee member, or designee representing the Region, by the tenth working day of the month following the month reported. Users should check with regions to determine reporting requirements.

Instructions for BA Survey. Using data derived from digital processing of the ACE signal, a representative from each BA will complete and submit CPS1 Form 1, "NERC Control Performance Standard Survey."

Hourly Table - Report the clock-hour average compliance factor (CF) for each of the 24 hourly periods and the total number of clock-minute sample averages in each clock-hour average.

CPS1 Standard Summary.

CPS1	CPS1 Month	Report the monthly compliance factor, percent compliance, and number of clock-minute sample averages and enter in this cell. This value is for the month, only and is critical to correct evaluation of 12-month compliance.
	CPS1 Rolling 12 Month Value	Report the rolling 12-month compliance factor, percent compliance, and number of samples and enter in this cell. This is your calculation of the rolling compliance. NERC will also make the calculation based on your monthly submittals.
	Number of Valid Samples	Enter number of valid clock-minute averages in the profile hour and total.
	Unavailable Periods	Enter number of unavailable 1-min periods in the profile hour and column total.

Instructions for Regional and NERC Surveys. From a review of the BAs' surveys, each Regional Survey Coordinator or RS member will ensure completion of CPS1 Form 2, "NERC Control Performance Standard — Regional Summary."

A. Review CPS1 Form 1 data received from each BA in the Region for uniformity, completeness, and compliance with the instructions. Iterate with BA survey coordinators where necessary.

B. Transfer the data from each Form to the appropriate columns on CPS1 Form 2 or its equivalent. Review the comments submitted and, if significant, identify them with the appropriate BAs.

C. Ensure forwarding of a copy each of the completed CPS Forms 1 and 2 or their equivalent to the NERC staff.

NERC staff will combine the Regional reports into a single summary report and post on the NERC Resources Subcommittee web page.

NERC Control Performance Standard Survey

CPS1 Form 1 BA -

Region - Month -

ε_1 – Year - Time Zone -

H.E.	CF	%	# of Valid 1-min Averages		Unavailable Periods	
0100				Record the total month's number of valid 1-min sample averages from each of the 24 hourly profile periods		Record the total unavailable periods from each of the month's 24 hourly profile periods
0200						
0300						
0400						
0500						
0600						
0700						
0800						
0900						
1000						
1100						
1200						
1300						
1400						
1500						
1600						
1700						
1800						
1900						
2000						
2100						
2200						
2300						
2400						
CPS1 Month -						
CPS1 – Rolling 12 Month Value						

Notes:

NERC Control Performance Standard Survey – Regional Summary				
CPS1 Form 2				
Region -	Month -			
Date -	Year -			
ID #	BA Name	Monthly CF	#Valid 1-min Averages	Monthly CPS1 %

Notes:

C. Control Performance Standard 2, CPS2

The second measure of the CPS survey is designed to bound ACE ten-minute averages and in doing so provides a means to limit excessive unscheduled power flows that could result from large ACEs.

Metrics.

Over a given period, the clock ten-minute averages of a BA's ACE is required by the standard to be less than the constant on the right-hand side of the following inequality during at least a percentage of the period as specified herein:

$$AVG_{10-\text{minute}}(ACE_i) \leq L_{10}$$

where: $$L_{10} = 1.65 \in_{10} \sqrt{(-10B_i)(-10B_s)}$$

$\in_{10}$ in Hz, is a constant derived from the targeted frequency bound. It is the targeted RMS of ten-minute average frequency error from schedule based on a selected historical period of interconnection frequency performance. The bound, $\in_{10}$, is the same for every BA within an Interconnection. In the ideal, it is also equal to epsilon1 divided by the square root of 10.

1.65 is a constant used to convert the frequency target to 90% probability. It is the number of standard deviations from the mean of a statistical normal distribution (Gaussian distribution) that will result in a probability of noncompliance of 10% (i.e., compliance of 90%).

$\mathbf{B_i}$ in (negative) MW per tenth Hz, is the frequency bias of the BA.

$\mathbf{B_s}$ in (negative) MW per tenth Hz, is the sum of the frequency bias settings of the BAs in the respective Interconnection; for systems with variable bias, this is equal to the sum of the minimum frequency bias settings.

For those systems with variable bias, CPS2 becomes:

$$AVG_{10-\text{minute}}(ACE) \leq L_{10}$$

where:

$$L_{10} = 1.65 \in_{10} [-10AVG_{10-\text{minute}}(B_i)]\sqrt{\frac{B_s}{B_{\text{minimum}}}}$$

B_{minimum} is the area's minimum allowed bias.

Compliance.

CPS2 compliance is achieved if the 10-minute ACE averages satisfy the inequality above for 90% (or more) of the intervals in a calendar month. The percentage, described below, is referred to as the CPS2 compliance percentage, or CPS2%.

Control Compliance Rating = Pass CPS2% $\geq$ 90%

Control Compliance Rating = Fail CPS2% < 90%

The compliance percentage is calculated as follows:

$$CPS2\% = \left[1 - \frac{\text{Violations}_{\text{month}}}{\left(\text{Total Periods}_{\text{month}} - \text{Unavailable Periods}_{\text{month}} \right)} \right] * 100$$

The $\text{Violations}_{\text{month}}$ are a count of the number of periods in which the average $\text{ACE}_{\text{clock-ten-minutes}}$ exceeded L_{10}. $\text{ACE}_{\text{clock-ten-minutes}}$ is the sum of valid ACE samples within a clock-ten-minute period divided by the number of valid samples (average ACE).

$$\text{Violation}_{\text{clock-ten-minutes}} = 0 \text{ if } \left| \frac{\sum ACE}{n_{\text{samples in 10-minutes}}} \right| \leq L_{10}$$

$$= 1 \text{ if } \left| \frac{\sum ACE}{n_{\text{samples in 10-minutes}}} \right| > L_{10}$$

Each area reports the total number of Violations and Unavailable Periods for the month.

Determination of Total $\text{Periods}_{\text{month}}$ and $\text{Violations}_{\text{month}}$

Since the CPS2 Criterion requires that ACE be averaged over a discrete time period, the same factors that limit Total $\text{Periods}_{\text{month}}$ will limit $\text{Violations}_{\text{month}}$. The calculation of Total $\text{Periods}_{\text{month}}$ and $\text{Violations}_{\text{month}}$, therefore, must be discussed jointly.

Each 24-hour period beginning at 0000 and ending at 2400 contains 144 discrete ten-minute periods (six periods more or less on Daylight Saving Time transition days). Each hour (HH) contains six discrete ten-minute periods, where period 1 spans HH:00^+ – HH:10, period 2 spans HH:10^+ – HH:20, period 3 spans HH:20^+ – HH:30, period 4 spans HH:30^+ – HH:40, period 5 spans HH:40^+ – HH:50, and period 6 spans HH:50^+ – (HH+1):00. For a system that samples ACE every four seconds, for example, the average ACE over a ten-minute period would be defined by the algebraic sum of 150 ACE samples (starting at HH:00:04 and ending at HH:10:00) divided by 150.

A CPS2 violation is recorded for any valid ten-minute period where the absolute value of average ACE is greater than L_{10}.

Interruption in the Recording of ACE – Valid Intervals

A condition may arise which may impact the normal calculation of Total $\text{Periods}_{\text{month}}$ and $\text{Violations}_{\text{month}}$. This condition is a sustained, unavoidable and uncontrollable interruption in the recording of ACE or one of its components.

In order to ensure that the average ACE calculated for any ten-minute interval is representative of that ten-minute interval, it is necessary that at least half the ACE data samples are present for that interval. The samples need not be contiguous. Such a period is a valid interval. Should more than half of the ACE data be unavailable due to loss of telemetering or computer unavailability, that ten-minute interval is not valid and is omitted from the calculation of CPS2.

Data Reporting.

The BA is responsible for submitting the Control Performance Standard survey each month. In addition (for post-reporting analysis by the Regional Resources Subcommittee representative), the BA is responsible for retaining sufficient pertinent data that will enable reproduction of the performance calculations.

Figure 1 demonstrates various examples of CPS2 compliance determination. Note that Figure 1 is separated into six distinct clock-ten-minute periods. The absolute value of the algebraic mean of the ACE during each period, referred to as d_a, is compared to L_{10} (10 MW for this system) to determine if there has been a violation for that period. Note that the fourth interval (0130 – 0140) has recorded a violation because the absolute value of the algebraic mean of 10.1 MW exceeds the L_{10} of 10 MW. Since disturbance conditions are included in the CPS2 calculation, violations are also recorded for the second and third intervals (0110–0120 & 0120–0130).

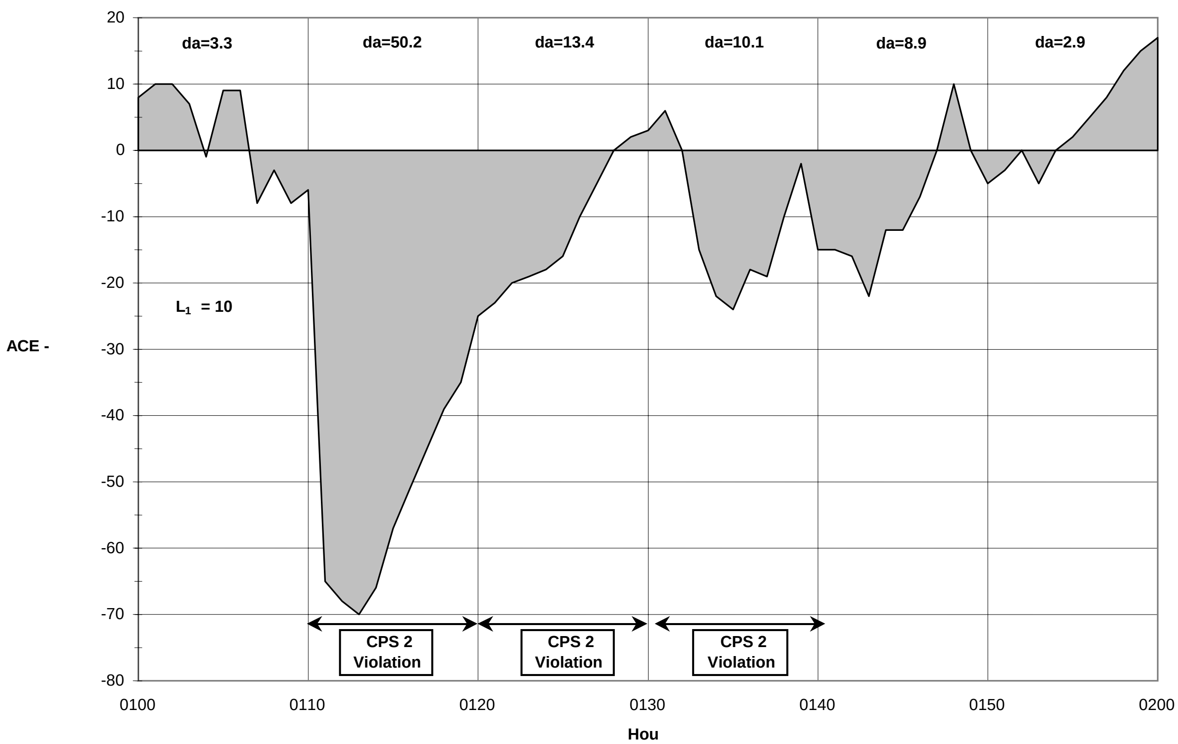


Figure 1 — CPS2-L_{10} Compliance Calculation Examples

Figure 2 demonstrates various examples of L_{10} compliance coupled with an interruption in the recording of ACE. At 1208, ACE recording was interrupted and not returned until 1218. Since the ACE recording for the interval 1210 – 1220 did not include at least five minutes of data, this period is eliminated from CPS compliance analysis. In contrast, the first ten-minute interval of 1200 – 1210 is included in the analysis because ACE recording was interrupted only for the last two minutes of the interval. In fact, the first interval is in violation because the absolute algebraic mean of 12.4 MW exceeds the L_{10} of 10.0 MW.

This algebraic mean of 12.4 MW was calculated for the eight minutes during which ACE was not interrupted. Thus, for this hour, there was one violation out of five valid intervals.

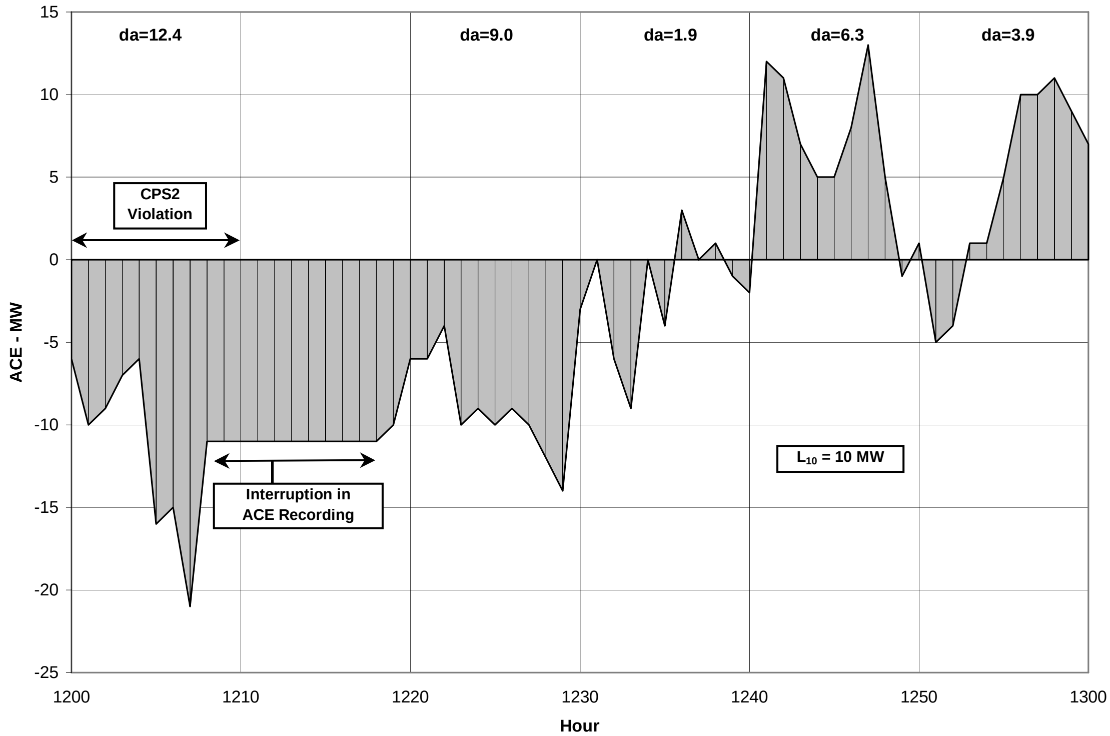


Figure 2 — CPS2-L_{10} Compliance & Data Interruption Effects

Surveys.

Performance Standard surveys are submitted monthly to analyze and demonstrate each BA's level of compliance with the Control Performance Standards. Completed surveys must be provided each month to the Resources Subcommittee member (or designee) representing the Region by the tenth working day of the month following the month being reported.

Instructions for BA Survey. Each BA will complete and submit CPS2 Form 1, "NERC Control Performance Standard Survey."

For each of the 24 hourly periods of a day, report the monthly total number of CPS2 violations and the number of unavailable ten-minute periods. For example, if there was one violation for hour ending 0100 every day of a 31-day month, a 31 would be entered for the 0100 hourly period.

CPS2 Standard Summary.

CPS2	TOTAL	Sum the number of sample averages, the number of violations, and unavailable ten-minute intervals recorded on the hourly tables and enter the sums in this row for each column.
	CPS2 (%)	Calculate the CPS2 percentage compliance and enter in

this row using the formulas and procedures described in Section C.

Instructions for Regional and NERC Surveys. From a review of the BAs' surveys, each Regional Survey Coordinator or RS member will ensure completion of CPS2 Form 2, "NERC Control Performance Standard — Regional Summary."

A. Review CPS2 Form 1 data received from each BA in the Region for uniformity, completeness, and compliance with the instructions. Iterate with BA survey coordinators where necessary.

B. Transfer the data from each Form to the appropriate columns on CPS Form 2. Review the comments submitted and, if significant, identify them with the appropriate BAs.

C. Forward a copy each of the completed CPS2 Forms 1 and 2 to the NERC staff..

D. NERC staff will combine the Regional reports into a single summary report and post on the NERC Resources Subcommittee web page.

NERC Control Performance Standard Survey

CPS2 Form 1 BA -

Region - Month -

L_{10} – Year -

H.E. CPT	Violations		Unavailable Periods	
0100		Record total violations for each of the 24 hourly profile periods		Record total unavailable periods for each of the 24 hourly profile periods
0200				
0300				
0400				
0500				
0600				
0700				
0800				
0900				
1000				
1100				
1200				
1300				
1400				
1500				
1600				
1700				
1800				
1900				
2000				
2100				
2200				
2300				
2400				
CPS2 Month -				

notes: Must be completed monthly and submitted to NERC Resources Subcommittee regional representative or designee by the 10th working day of the month following the month reported.

NERC Control Performance Standard Survey – Regional Summary				
CPS2 Form 2				
Region -	**Month -**			
Date -	**Year -**			

ID #	BA Name	Violations	Unavailable Periods	Monthly CPS2 %

notes:

D. Disturbance Control Standard, DCS

During a disturbance, controls cannot usually maintain ACE within the criteria for normal load variation. Balancing areas, alone or collectively through reserve-sharing groups, are expected to activate contingency reserve to cause recovery of ACE magnitude within fifteen minutes following the start of a disturbance. This requires that a disturbance be defined. A disturbance is a sudden, unanticipated change (contingency) in resource(s) or demand. A sudden change is one that takes place over a minute or less. The DCS focuses on reportable disturbances.

Fifteen minutes is the existing recovery period duration which has evolved from debate over the appropriate way to measure the deployment of what has been measured as 10-minute reserves. It was argued that all balancing authorities need time to assess the validity of what appears to be a disturbance, and reserve-sharing groups need time to propagate calls for contingency reserves. Analyses were undertaken to determine probabilistically how lengthening the recovery period from 10 to 15 minutes would increase exposure to a second contingency. It was determined that the effect was very small, and recoverability from the next contingency is largely driven by reserve restoration timing, anyway. The 15 minute recovery standard was passed for recommendation by the NERC Resources Subcommittee in October, 1999.

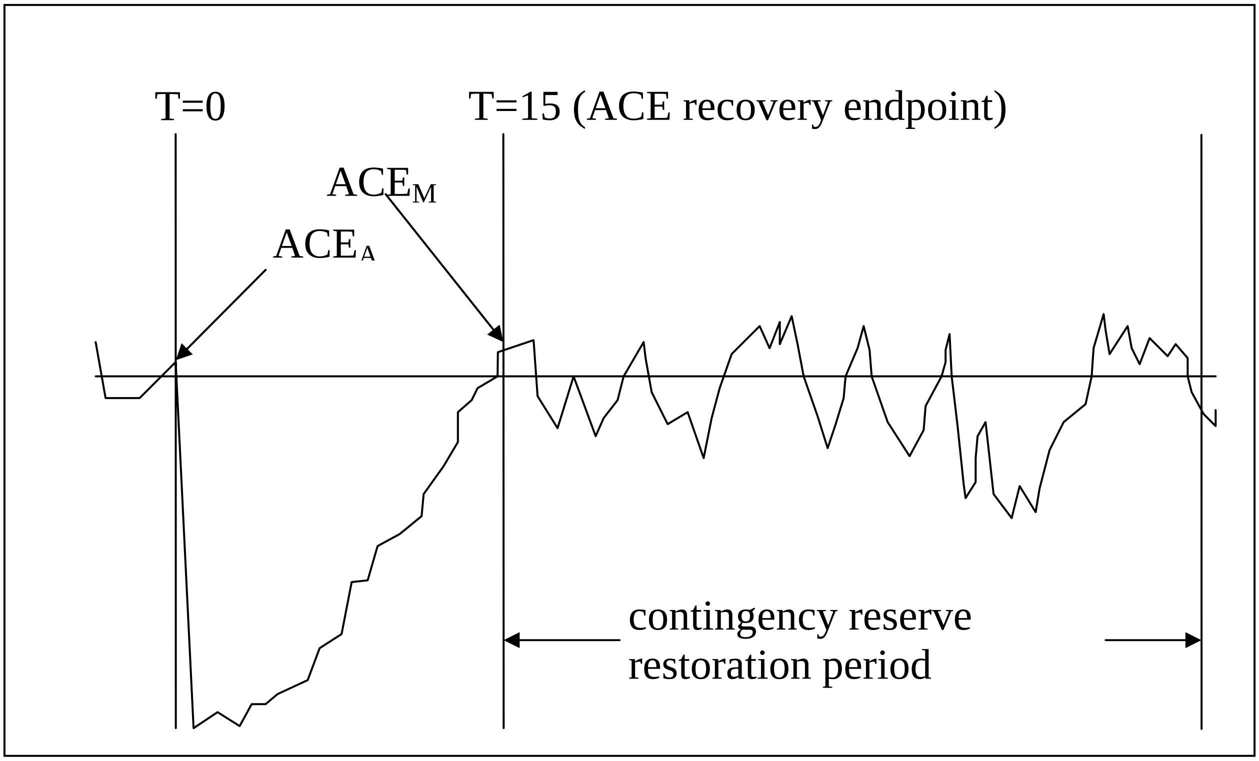
For purposes of disturbance control compliance, reportable disturbances are contingencies that are greater than or equal to 80% of the most severe single contingency loss. The start of a disturbance is the time of the event as best defined by resource output decline, breaker opening, or other such indication – in the absence of such indication, the moment of first ACE deflection may be used. The start of the recovery period is the same moment as the start of the disturbance. Note that the start of a disturbance and its magnitude are determined by the resource or demand change, while recovery and compliance are determined by ACE.

Regions may optionally reduce the 80% reporting threshold, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal load and generation excursions (e.g., pumped storage hydro, arc furnace, rolling steel mill, etc.) that influence ACE are not reportable disturbance conditions. Normal operating characteristics are excluded because <u>DCS strives to measure the recovery from sudden, unanticipated changes in demand or supply-side resources</u>.

Metrics

Balancing Area. A BA is to return its ACE either to zero or to its pre-disturbance ACE level within a recovery time of fifteen minutes following the start of a disturbance. A BA may, at its discretion, **measure** its compliance based on the ACE measured fifteen minutes after the start of the disturbance, or on the maximum ACE recovery measured within the fifteen minutes following the start of the disturbance.

Reserve Sharing Group (RSG). The disturbance control compliance for a BA within an RSG is based on the compliance of the RSG (according to the compliance method chosen). An RSG may, at its discretion, measure this recovery based on the combined ACE measured fifteen minutes after the start of the disturbance, or on the maximum combined coincidental ACE recovery measured within the fifteen minutes following the start of the disturbance event (<u>not</u> the time at which reserve activation was requested).



Relationships among ACE, the 15-minute recovery period, and the reserve restoration period

Compliance

A BA or RSG must calculate and report compliance with the Disturbance Control Standard for all disturbances greater than or equal to 80% of the magnitude of the BA's or the RSG's most severe single contingency loss. Regional Reliability Councils may, at their discretion, require a lower reporting threshold. Disturbance Control Standard compliance is measured as the percentage recovery, $R_{i.}$ R_i >= 100% represents full compliance.

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 event. It is the size of the resource or demand loss, not the ACE deflection,

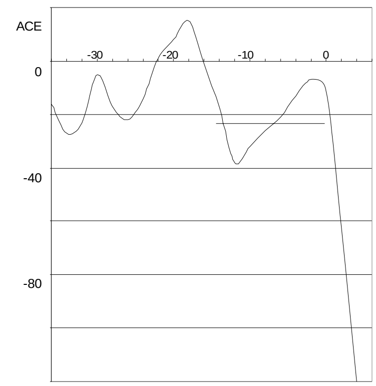
ACE_A is the pre-disturbance ACE,

ACE_M is the value of ACE representing the point of greatest recovery from the disturbance measured within the fifteen minutes following the start of the disturbance event. A BA or RSG may, at their discretion, set $ACE_M = ACE_{15\ min}$.

a. Determination of MW_{LOSS}.

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.

b. Determination of ACE_A.



Base the value for ACE_A on the average ACE over the period just prior to the start of the disturbance. Average over a period between 10 and 60 seconds prior and include at least 4 scans of ACE. In the illustration to the right, 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.

c. Determination of ACE_M.

ACE_M is the value of ACE representing the point of greatest recovery from the disturbance measured within fifteen minutes following the start of the disturbance. It is negative for typical generation loss disturbances where zero is not reached within the recovery interval. At the discretion of the BA or of the RSG, compliance may be based on the ACE measured fifteen minutes following the start of the disturbance, i.e., $ACE_M = ACE_{15\ min}$.

Figure 1 demonstrates compliance evaluation during a disturbance condition (Disturbance Control Standard). Note the pattern of the disturbance condition, which began at 0110, the time at which ACE deflection exceeds this entity's disturbance reporting threshold of 50 MW. During this disturbance, the Disturbance Control Standard was violated because ACE was not restored to its pre-contingency level until 0127 (a 17-minute interval which violates the Disturbance Control Standard).

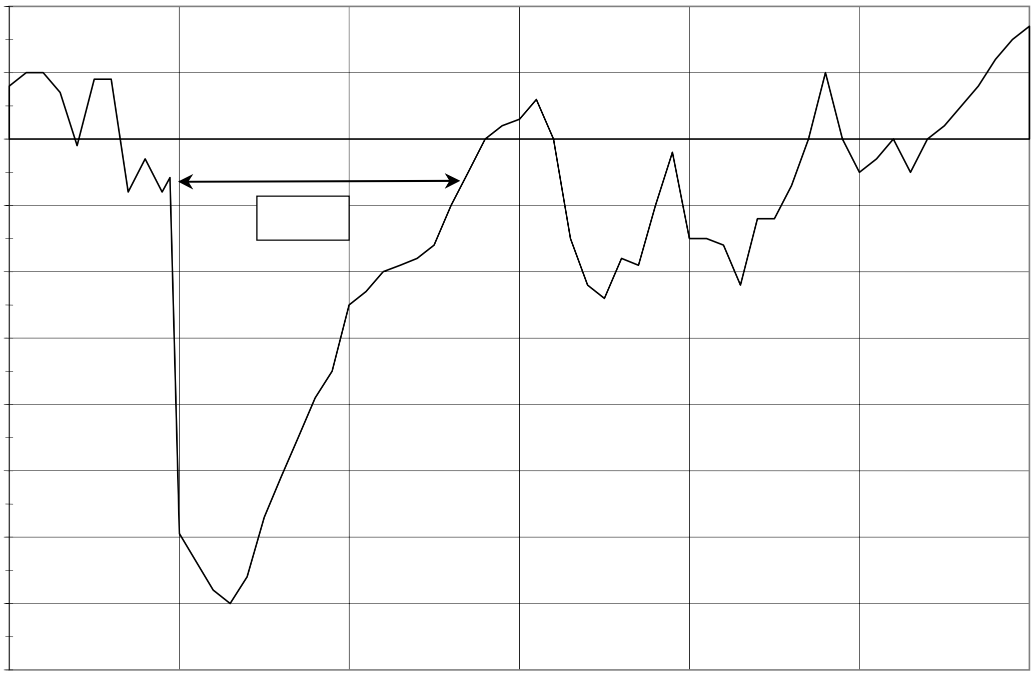


Figure 1 — CPS2-L_{10} Compliance & Disturbance Control Standard, 2 Disturbance Examples

Reporting

Each BA or RSG is to report its Disturbance Control Standard compliance quarterly. The completed Disturbance Control Standard survey is to be supplied to NERC by the 20th day following the end of the respective quarter. Where RSGs exist, the Regional Reliability Council is to decide either to report these on a BA basis or on an RSG basis. If an RSG has dynamic membership or allocates reserves dynamically, then it will be required that the Region convert the disturbance reporting for the RSG to a BA basis before reporting to NERC. If a BA basis is selected, each BA reports the RSG's performance only for disturbances occurring in their area.

a. **Reportable Disturbance.** The definition of reportable disturbance magnitude is to be provided to NERC by the respective Regional Reliability Councils. The definition is to include events that are greater than or equal to 80% of a BA's or RSG's most severe single contingency. The definition of a reportable disturbance must be specified in the operating Policy adopted by each Regional Reliability Council. This definition may not be retroactively adjusted in response to observed performance.

1. **Most Severe Single Contingency.** A BA's most severe single contingency is defined as the magnitude of the largest single credible event that would cause the greatest change in the BA's ACE, or as defined by the respective Regional Council. It is not necessarily a single loss; it could be an entire generating station, or a loss from transmission facility or facilities contingency.

2. **Excludable Disturbances and Average Percent Recovery.** The BA or RSG is to report both the number of reportable disturbances that occur in the given quarter, and the average percent recovery for that quarter. The report must also indicate excludable disturbances that occurred in the quarter and the average percent recovery for those excluded events.

3. **Excludable Disturbance.** An excludable disturbance is a disturbance whose magnitude was greater than the magnitude of the most severe single contingency.

4. **Average Percent Recovery.** The average percent recovery is the arithmetic average of all the calculated R_is from reportable disturbances during the given quarter. Average percent recovery is similarly calculated for excludable disturbances. (See calculation of R_i below).

5. **Contingency Reserve Adjustment Factor (CRAF)**. The quarterly Contingency Reserve Adjustment factor is to include only those reportable disturbances with magnitudes less than or equal to the magnitude of the respective BA's most severe single contingency.

CRAF is defined as follows:

when $n_{Quarter} \geq 0$, then

$$CRAF_{Quarter} = 200 - \left[\frac{\sum R_i}{n_{Quarter}} \right]$$

when $n_{Quarter} = 0$, then $CRA_{Quarter} = 100$

where $n_{Quarter}$ is the number of reportable disturbances experienced during the reporting quarter.

i = reportable disturbances.

R_i is defined in section C.2.

Calculation Precision. The Adjustment Factor is to be rounded off to two decimal places.

6. **Exemptions**. Requests for exemptions for single events that cause multiple reportable disturbances (e.g. hurricanes, earthquakes, islanding, etc.) is to be submitted to the NERC Director of Compliance. Until the exemption is approved or denied, the BA or RSG is to consider the request denied.

7. **Contingency Reserve Adjustment Period.** BAs are to revise their respective Contingency Reserve Requirement by their computed Contingency Reserve Adjustment factor. The adjustments will be effective starting one month following the end of the reported quarter and remain in effect for three months.

8. **Report Filing.** Each BA or RSG is to report its Disturbance Control Standard compliance quarterly, by the 10th working day following the end of the quarter, on Form DCS "NERC Disturbance Control Standard Survey."

    a. Mail a copy of the completed Form DCS to the NERC staff.

    b. NERC staff will combine the Regional reports into a single summary report and make copies available to each Resources Subcommittee member and others with a legitimate need to know.

NERC Disturbance Control Standard Report

	Disturbances Not Greater than the Most Severe Single Contingency Loss		Disturbances Greater than the Most Severe Single Contingency Loss[3]		This Quarter's CRAF[4]	Criteria for Determining Reportable Disturbances This Report	Criteria for Determining Reportable Disturbances Next Report
Quarter:							
Year:							
Region:							
Control Area/RSG[1]:	Number	APR[2] (a)	Number	APR			

[1] When reporting as a Reserve Sharing Group (RSG), submit data for the entire group only and list the Control Areas comprising the RSG.
[2] APR indicates the Average Percent Recovery.
[3] Not a performance measure. For informational purposes only.
[4] [200-(a)], please round to the nearest whole percentage.

NOTES/COMMENTS:

A Control Area or Reserve Sharing Group must increase their Contingency Reserve Requirement by the CRAF. CRR changes are implemented one month after the end of a reporting quarter and remain in effect for three months.