

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAC approves Version 0 SAR for posting (April 14, 2004).
2. SAC approves *Plan for Accelerating Adoption of NERC Reliability Standards* (April 19, 2004).
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7. JIC assigns Version 0 reliability standards to NERC and business practices to NAESB (August 16, 2004).
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Description of Current Draft:

Draft 3 is to be posted for a 30-day posting prior to balloting the Version 0 standards. This draft includes revisions based on industry comments received during the posting of Draft 2. Changes from Draft 2 are highlighted in the redline copy of Draft 3.

Future Development Plan:

Anticipated Actions

Anticipated Date

- | | |
|---|--|
| 1. Seek endorsement of NERC technical committees. | November 9–11, 2004 |
| 2. First ballot of Version 0 standards. | December 1–10, 2004 |
| 3. Recirculation ballot of Version 0 standards. | December 27, 2004 –
January 7, 2005 |
| 4. 30-day posting before board adoption. | January 8, 2005 –
February 8, 2005 |
| 5. Board adopts Version 0 standards. | February 8, 2005 |
| 6. Effective date. | April 1, 2005 |

A. Introduction

1. **Title:** Real Power Balancing Control Performance
2. **Number:** BAL-001-0
3. **Purpose:** To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.
4. **Applicability:**
 - 4.1. Balancing Authorities
5. **Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority’s Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area’s Frequency Bias) times the corresponding clock-minute averages of the Interconnection’s Frequency Error is less than a specific limit. This limit ϵ_1^2 is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the NERC Operating Committee.

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

The equation for ACE is:

$$ACE = (NI_A - NI_S) - 10B (F_A - F_S) - I_{ME}$$

where:

- NI_A is the algebraic sum of actual flows on all tie lines.
- NI_S is the algebraic sum of scheduled flows on all tie lines.
- B is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.
- F_A is the actual frequency.
- F_S is the scheduled frequency. F_S is normally 60 Hz but may be offset to effect manual time error corrections.
- I_{ME} is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.

- R2.** Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10} .

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

where:

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

ϵ_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average Frequency Error based on frequency performance over a given year. The bound, ϵ_{10} , is the same for every Balancing Authority Area within an Interconnection, and B_s is the sum of the Frequency Bias Settings of the Balancing Authority Areas in the respective Interconnection. For Balancing Authority Areas with variable bias, this is equal to the sum of the minimum Frequency Bias Settings.

- R3.** Each Balancing Authority providing Overlap Regulation Service shall evaluate Requirement R1 (i.e., Control Performance Standard 1 or CPS1) and Requirement R2 (i.e., Control Performance Standard 2 or CPS2) using the characteristics of the combined ACE and combined Frequency Bias Settings.
- R4.** Any Balancing Authority receiving Overlap Regulation Service shall not have its control performance evaluated (i.e. from a control performance perspective, the Balancing Authority has shifted all control requirements to the Balancing Authority providing Overlap Regulation Service).

C. Measures

- M1.** Each Balancing Authority shall achieve, as a minimum, Requirement 1 (CPS1) compliance of 100%.

CPS1 is calculated by converting a compliance ratio to a compliance percentage as follows:

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

The frequency-related compliance factor, CF, is a ratio of all one-minute compliance parameters accumulated over 12 months divided by the target frequency bound:

$$CF = \frac{CF_{12\text{-month}}}{(\epsilon_1)^2}$$

where: ϵ_1 is defined in Requirement R1.

The rating index $CF_{12\text{-month}}$ is derived from 12 months of data. The basic unit of data comes from one-minute averages of ACE, Frequency Error and Frequency Bias Settings.

A clock-minute average is the average of the reporting Balancing Authority's valid measured variable (i.e., for ACE and for Frequency Error) for each sampling cycle during a given clock-minute.

$$\left(\frac{ACE}{-10B} \right)_{\text{clock-minute}} = \frac{\left(\frac{\sum ACE_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}} \right)}{-10B}$$

$$\Delta F_{\text{clock-minute}} = \frac{\sum \Delta F_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}$$

The Balancing Authority's clock-minute compliance factor (CF) becomes:

$$CF_{\text{clock-minute}} = \left[\left(\frac{ACE}{-10B} \right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}} \right]$$

Normally, sixty (60) clock-minute averages of the reporting Balancing Authority's ACE and of the respective Interconnection's Frequency Error will be used to compute the respective hourly average compliance parameter.

$$CF_{\text{clock-hour}} = \frac{\sum CF_{\text{clock-minute}}}{n_{\text{clock-minute samples in hour}}}$$

The reporting Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages (CF clock-hour average-month) as well as the respective number of samples for each of the twenty-four (24) hours (one for each clock-hour, i.e., hour-ending (HE) 0100, HE 0200, ..., HE 2400).

$$CF_{\text{clock-hour average-month}} = \frac{\sum_{\text{days-in-month}} [(CF_{\text{clock-hour}})(n_{\text{one-minute samples in clock-hour}})]}{\sum_{\text{days-in month}} [n_{\text{one-minute samples in clock-hour}}]}$$

$$CF_{\text{month}} = \frac{\sum_{\text{hours-in-day}} [(CF_{\text{clock-hour average-month}})(n_{\text{one-minute samples in clock-hour averages}})]}{\sum_{\text{hours-in day}} [n_{\text{one-minute samples in clock-hour averages}}]}$$

The 12-month compliance factor becomes:

$$CF_{12\text{-month}} = \frac{\sum_{i=1}^{12} (CF_{\text{month-}i})(n_{(\text{one-minute samples in month-}i)})}{\sum_{i=1}^{12} [n_{(\text{one-minute samples in month-}i)}]}$$

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 samples during that one-minute interval be present. Should a sustained interruption in the recording of ACE or Frequency Deviation due to loss of telemetering or computer unavailability result in a one-minute interval not containing at least 50% of samples of both ACE and Frequency Deviation, that one-minute interval shall be excluded from the calculation of CPS1.

- M2.** Each Balancing Authority shall achieve, as a minimum, Requirement R2 (CPS2) compliance of 90%. CPS2 relates to a bound on the ten-minute average of ACE. A compliance percentage is calculated as follows:

$$CPS2 = \left[1 - \frac{\text{Violations}_{\text{month}}}{(\text{Total Periods}_{\text{month}} - \text{Unavailable Periods}_{\text{month}})} \right] * 100$$

The violations per month are a count of the number of periods that ACE clock-ten-minutes exceeded L_{10} . ACE clock-ten-minutes is the sum of valid ACE samples within a clock-ten-minute period divided by the number of valid samples.

Violation clock-ten-minutes

$$\left| \frac{\sum ACE}{n_{\text{samples in 10-minutes}}} \right| \leq L_{10} \quad = 0 \text{ if}$$

$$\left| \frac{\sum ACE}{n_{\text{samples in 10-minutes}}} \right| > L_{10} \quad = 1 \text{ if}$$

Each Balancing Authority shall report the total number of violations and unavailable periods for the month. L_{10} is defined in Requirement R2.

Since CPS2 requires that ACE be averaged over a discrete time period, the same factors that limit total periods per month will limit violations per month. The calculation of total periods per month and violations per month, therefore, must be discussed jointly.

A condition may arise which may impact the normal calculation of total periods per month and violations per month. This condition is a sustained interruption in the recording of ACE.

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. Should half or more of the ACE data be unavailable due to loss of telemetering or computer unavailability, that ten-minute interval shall be omitted from the calculation of CPS2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar month.

1.3. Data Retention

The data that supports the calculation of CPS1 and CPS2 (Attachment 1-BAL-001-0) are to be retained in electronic form for at least a one-year period. If the CPS1 and CPS2 data for a Balancing Authority Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved. Each Balancing Authority shall retain for a rolling 12-month period the values of: one-minute average ACE (ACE_i), one-minute average Frequency Error, and, if using variable bias, one-minute average Frequency Bias.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance – CPS1

2.1. Level 1: The Balancing Authority Area's value of CPS1 is less than 100% but greater than or equal to 95%.

2.2. Level 2: The Balancing Authority Area's value of CPS1 is less than 95% but greater than or equal to 90%.

2.3. Level 3: The Balancing Authority Area's value of CPS1 is less than 90% but greater than or equal to 85%.

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- 2.4. **Level 4:** The Balancing Authority Area's value of CPS1 is less than 85%.
- 3. **Levels of Non-Compliance – CPS2**
 - 3.1. **Level 1:** The Balancing Authority Area's value of CPS2 is less than 90% but greater than or equal to 85%.
 - 3.2. **Level 2:** The Balancing Authority Area's value of CPS2 is less than 85% but greater than or equal to 80%.
 - 3.3. **Level 3:** The Balancing Authority Area's value of CPS2 is less than 80% but greater than or equal to 75%.
 - 3.4. **Level 4:** The Balancing Authority Area's value of CPS2 is less than 75%.

E. Regional Differences

- 1. The [ERCOT Control Performance Standard 2 Waiver](#) approved November 21, 2002.

Version History

Version	Date	Action	Change Tracking
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Attachment 1-BAL-001-0
CPS1 and CPS2 Data

CPS1 DATA	Description	Retention Requirements
ε_1	A constant derived from the targeted frequency bound. This number is the same for each Balancing Authority Area in the Interconnection.	Retain the value of ε_1 used in CPS1 calculation.
ACE_i	The clock-minute average of ACE.	Retain the 1-minute average values of ACE (525,600 values).
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value(s) of B_i used in the CPS1 calculation.
F_A	The actual measured frequency.	Retain the 1-minute average frequency values (525,600 values).
F_S	Scheduled frequency for the Interconnection.	Retain the 1-minute average frequency values (525,600 values).

CPS2 DATA	Description	Retention Requirements
V	Number of incidents per hour in which the absolute value of ACE clock-ten-minutes is greater than L_{10} .	Retain the values of V used in CPS2 calculation.
ε_{10}	A constant derived from the frequency bound. It is the same for each Balancing Authority Area within an Interconnection.	Retain the value of ε_{10} used in CPS2 calculation.
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value of B_i used in the CPS2 calculation.
B_s	The sum of Frequency Bias of the Balancing Authority Areas in the respective Interconnection. For systems with variable bias, this is equal to the sum of the minimum Frequency Bias Setting.	Retain the value of B_s used in the CPS2 calculation. Retain the 1-minute minimum bias value (525,600 values).
U	Number of unavailable ten-minute periods per hour used in calculating CPS2.	Retain the number of 10-minute unavailable periods used in calculating CPS2 for the reporting period.

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January 7, 2005
January 8, 2005–
February 8, 2005
February 8, 2005
April 1, 2005

Introduction

1. Title: Disturbance Control Performance

2. Number: BAL-002-0

3. Purpose:

The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.

4. Applicability:

4.1. Balancing Authorities

4.2. Reserve Sharing Groups (Balancing Authorities may meet the requirements of Standard 002 through participation in a Reserve Sharing Group.)

4.3. Regional Reliability Organizations

5. Proposed Effective Date: April 1, 2005

B. Requirements

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

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

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

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

R2.2. Its allocation among members.

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

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

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

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

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

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

- R4.** A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:
- R4.1.** A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.
 - R4.2.** The default Disturbance Recovery Period is 15 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the NERC Operating Committee.
- R5.** Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:
- R5.1.** The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.

or

 - R5.2.** The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.
- R6.** A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection.
- R6.1.** The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.
 - R6.2.** The default Contingency Reserve Restoration Period is 90 minutes. This period may be adjusted to better suit the reliability targets of the Interconnection based on analysis approved by the NERC Operating Committee.

C. Measures

- M1.** A Balancing Authority or Reserve Sharing Group shall calculate and report compliance with the Disturbance Control Standard for all Disturbances greater than or equal to 80% of the magnitude of the Balancing Authority's or of the Reserve Sharing Group's most severe single contingency loss. Regions may, at their discretion, require a lower reporting threshold. Disturbance Control Standard is measured as the percentage recovery (R_1).

For loss of generation:

if $ACE_A < 0$
then

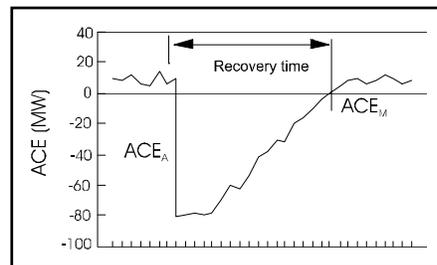
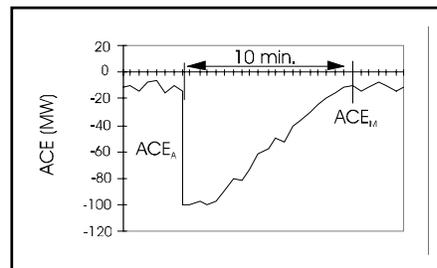
$$R_i = \frac{MW_{Loss} - \max(0, ACE_A - ACE_M)}{MW_{Loss}} * 100\%$$

if $ACE_A \geq 0$
then

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

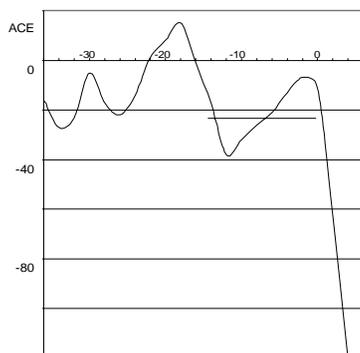
where:

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



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

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



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

D. Compliance

1. Compliance Monitoring Process

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

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

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

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

1.3. Data Retention

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

1.4. Additional Compliance Information

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

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

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

Multiple Contingencies within the Contingency Reserve Restoration Period – Additional Reportable Disturbances that occur after the end of the Disturbance Recovery Period but before the end of the Contingency Reserve Restoration Period

shall be reported and included in the compliance evaluation. However, the Balancing Authority or Reserve Sharing Group can request a waiver from the Resources Subcommittee for the event if the contingency reserves were rendered inadequate by prior contingencies and a good faith effort to replace contingency reserve can be shown.

2. Levels of Non-Compliance

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

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

- 2.1. Level 1:** Value of the average percent recovery for the quarter is less than 100% but greater than or equal to 95%.
- 2.2. Level 2:** Value of the average percent recovery for the quarter is less than 95% but greater than or equal to 90%.
- 2.3. Level 3:** Value of average percent recovery for the quarter is less than 90% but greater than or equal to 85%.
- 2.4. Level 4:** Value of average percent recovery for the quarter is less than 85%.

E. Regional Differences

None identified.

Version History

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A. Introduction

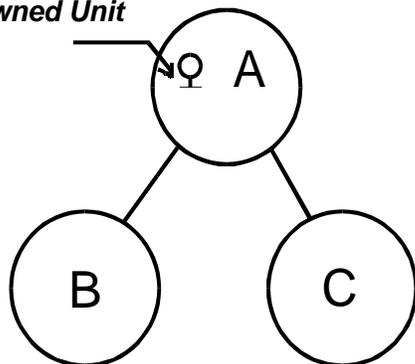
- 1. Title:** Frequency Response and Bias
- 2. Number:** BAL-003-0
- 3. Purpose:**
This standard provides a consistent method for calculating the Frequency Bias component of ACE.
- 4. Applicability:**
 - 4.1.** Balancing Authorities
- 5. Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** Each Balancing Authority shall review its Frequency Bias Settings by January 1 of each year and recalculate its setting to reflect any change in the Frequency Response of the Balancing Authority Area.
 - R1.1.** The Balancing Authority may change its Frequency Bias Setting, and the method used to determine the setting, whenever any of the factors used to determine the current bias value change.
 - R1.2.** Each Balancing Authority shall report its Frequency Bias Setting, and method for determining that setting, to the NERC Operating Committee.
- R2.** Each Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency Response. Frequency Bias may be calculated several ways:
 - R2.1.** The Balancing Authority may use a fixed Frequency Bias value which is based on a fixed, straight-line function of Tie Line deviation versus Frequency Deviation. The Balancing Authority shall determine the fixed value by observing and averaging the Frequency Response for several Disturbances during on-peak hours.
 - R2.2.** The Balancing Authority may use a variable (linear or non-linear) bias value, which is based on a variable function of Tie Line deviation to Frequency Deviation. The Balancing Authority shall determine the variable frequency bias value by analyzing Frequency Response as it varies with factors such as load, generation, governor characteristics, and frequency.
- R3.** Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.
- R4.** Balancing Authorities that use Dynamic Scheduling or Pseudo-ties for jointly owned units shall reflect their respective share of the unit governor droop response in their respective Frequency Bias Setting.
 - R4.1.** Fixed schedules for Jointly Owned Units mandate that Balancing Authority (A) that contains the Jointly Owned Unit must incorporate the respective share of the unit governor droop response for any Balancing Authorities that have fixed schedules (B and C). See the diagram below.

R4.2. The Balancing Authorities that have a fixed schedule (B and C) but do not contain the Jointly Owned Unit shall not include their share of the governor droop response in their Frequency Bias Setting.

Jointly Owned Unit



R5. Balancing Authorities that serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of the Balancing Authority’s estimated yearly peak demand per 0.1 Hz change.

R5.1. Balancing Authorities that do not serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of its estimated maximum generation level in the coming year per 0.1 Hz change.

R6. A Balancing Authority that is performing Overlap Regulation Service shall increase its Frequency Bias Setting to match the frequency response of the entire area being controlled. A Balancing Authority shall not change its Frequency Bias Setting when performing Supplemental Regulation Service.

C. Measures

M1. Each Balancing Authority shall perform Frequency Response surveys when called for by the Operating Committee to determine the Balancing Authority’s response to Interconnection Frequency Deviations.

D. Compliance

Not Specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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Standard Development Roadmap

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Anticipated Date

November 9–11, 2004
December 1–10, 2004
December 27, 2004–
January 7, 2005
January 8, 2005–
February 8, 2005
February 8, 2005
April 1, 2005

A. Introduction

1. Title: Time Error Correction

2. Number: BAL-004-0

3. Purpose:

The purpose of this standard is to ensure that Time Error Corrections are conducted in a manner that does not adversely affect the reliability of the Interconnection.

4. Applicability:

4.1. Reliability Coordinators

4.2. Balancing Authorities

5. Proposed Effective Date: April 1, 2005

B. Requirements

R1. Only a Reliability Coordinator shall be eligible to act as Interconnection Time Monitor. A single Reliability Coordinator in each Interconnection shall be designated by the NERC Operating Committee to serve as Interconnection Time Monitor.

R2. The Interconnection Time Monitor shall monitor Time Error and shall initiate or terminate corrective action orders in accordance with the NAESB Time Error Correction Procedure.

R3. Each Balancing Authority, when requested, shall participate in a Time Error Correction by one of the following methods:

R3.1. The Balancing Authority shall offset its frequency schedule by 0.02 Hertz, leaving the Frequency Bias Setting normal; or

R3.2. The Balancing Authority shall offset its Net Interchange Schedule (MW) by an amount equal to the computed bias contribution during a 0.02 Hertz Frequency Deviation (i.e. 20% of the Frequency Bias Setting).

R4. Any Reliability Coordinator in an Interconnection shall have the authority to request the Interconnection Time Monitor to terminate a Time Error Correction in progress, or a scheduled Time Error Correction that has not begun, for reliability considerations.

R4.1. Balancing Authorities 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.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Standard BAL-004-0 — Time Error Correction

Version History

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Anticipated Date

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February 8, 2005
February 8, 2005
April 1, 2005

A. Introduction

1. Title: Automatic Generation Control

2. Number: BAL-005-0

3. Purpose:

This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Area so that balancing of resources and demand can be achieved.

4. Applicability:

4.1. Balancing Authorities

4.2. Generator Operators

4.3. Transmission Operators

4.4. Load Serving Entities

5. Proposed Effective Date: April 1, 2005

B. Requirements

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

R1.1. Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.

R1.2. Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.

R1.3. Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.

R2. Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.

R3. A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.

R4. A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.

R5. A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.

R6. The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes it shall notify its Reliability Coordinator.

- R7.** The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.
- R8.** The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every six seconds.
- R8.1.** Each Balancing Authority 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%.
- R9.** The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.
- R9.1.** Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority 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.
- R10.** The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.
- R11.** Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.
- R12.** Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.
- R12.1.** Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.
- R12.2.** Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-aliasing Filters of Tie Lines.
- R12.3.** Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of Jointly Owned Units or to serve remote load.
- R13.** Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority 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.
- R14.** The Balancing Authority shall provide its operating personnel 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 Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.
- R15.** The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority'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.

R16. The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.

R17. Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

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

C. Measures

Not specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Balancing Authorities shall be prepared to supply data to NERC in the format defined below:

1.1.1. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization CPS source data in daily CSV files with time stamped one minute averages of: 1) ACE and 2) Frequency Error.

1.1.2. Within one week upon request, Balancing Authorities shall provide NERC or the Regional Reliability Organization DCS source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Error for a time period of two minutes prior to thirty minutes after the identified Disturbance.

1.2. Compliance Monitoring Period and Reset Timeframe

Not specified.

1.3. Data Retention

1.3.1. Each Balancing Authority 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.

1.3.2. Each Balancing Authority 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 Balancing Authority or Reserve Sharing Group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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1. Seek endorsement of NERC technical committees.	November 9-11, 2004
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4. 30-day posting before board adoption.	January 8, 2005– February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. Title: Inadvertent Interchange

2. Number: BAL-006-0

3. Purpose:

This standard defines a process for monitoring Balancing Authorities to ensure that, over the long term, Balancing Authority Areas do not excessively depend on other Balancing Authority Areas in the Interconnection for meeting their demand or Interchange obligations.

4. Applicability:

4.1. Balancing Authorities.

5. Proposed Effective Date April 1, 2005

B. Requirements

R1. Each Balancing Authority shall calculate and record hourly Inadvertent Interchange.

R2. Each Balancing Authority shall include all AC tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators.

R3. Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.

R4. Adjacent Balancing Authority 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 Balancing Authority shall compute its Inadvertent Interchange based on the following:

R4.1. Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to:

R4.1.1. The hourly values of Net Interchange Schedule.

R4.1.2. The hourly integrated megawatt-hour values of Net Actual Interchange.

R4.2. Each Balancing Authority 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.

R4.3. A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed 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 Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authority(ies).

R5. Adjacent Balancing Authorities 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 Regional Reliability Organization Survey Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy.

C. Measures

None specified.

D. Compliance

1. Compliance Monitoring Process

- 1.1. Each Balancing Authority shall submit a monthly summary of Inadvertent Interchange. These summaries shall not include any after-the-fact changes that were not agreed to by the Source Balancing Authority, Sink Balancing Authority and all Intermediate Balancing Authority(ies).
- 1.2. 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.
- 1.3. Each Balancing Authority shall submit its monthly summary report to its Regional Reliability Organization Survey Contact by the 15th calendar day of the following month.
- 1.4. Each Balancing Authority shall perform an Area Interchange Error (AIE) Survey as requested by the NERC Operating Committee to determine the Balancing Authority's Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance.
- 1.5. Each Regional Reliability Organization shall prepare a monthly Inadvertent Interchange summary to monitor the Balancing Authorities' monthly Inadvertent Interchange and all-time accumulated Inadvertent Interchange. Each Regional Reliability Organization shall submit a monthly accounting to NERC by the 22nd day following the end of the month being summarized.

2. Levels of Non Compliance

A Balancing Authority that neither submits a report to the Regional Reliability Organization Survey Contact, nor supplies a reason for not submitting the required data, by the 20th calendar day of the following month shall be considered non-compliant.

E. Regional Differences

- 1. MISO RTO Inadvertent Interchange Accounting Waiver approved by the Operating Committee on March 25, 2004.

Version History

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Anticipated Date

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December 1–10, 2004
December 27, 2004 –
January 7, 2005
January 8, 2005 –
February 8, 2005
February 8, 2005
April 1, 2005

A. Introduction

- 1. Title:** **Transmission Operations**
- 2. Number:** TOP-004-0
- 3. Purpose:** To ensure that the transmission system is operated so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single Contingency and specified multiple Contingencies.
- 4. Applicability:**
 - 4.1.** Transmission Operators
- 5. Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** Each Transmission Operator shall operate within the Interconnection Reliability Operating Limits (IROLs) and System Operating Limits (SOLs).
- R2.** Each Transmission Operator shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency.
- R3.** Each Transmission Operator shall, when practical, operate to protect against instability, uncontrolled separation, or cascading outages resulting from multiple outages, as specified by Regional Reliability Organization policy.
- R4.** If a Transmission Operator 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.
- R5.** Each Transmission Operator shall make every effort to remain connected to the Interconnection. If the Transmission Operator determines that by remaining interconnected, it is in imminent danger of violating an IROL or SOL, the Transmission Operator may take such actions, as it deems necessary, to protect its area.
- R6.** Transmission Operators, individually and jointly with other Transmission Operators, shall develop, maintain, and implement formal policies and procedures to provide for transmission reliability. These policies and procedures shall address the execution and coordination of activities that impact inter- and intra-Regional reliability, including:
 - R6.1.** Equipment ratings.
 - R6.2.** Monitoring and controlling voltage levels and real and reactive power flows.
 - R6.3.** Switching transmission elements.
 - R6.4.** Planned outages of transmission elements.
 - R6.5.** Development of IROLs and SOLs.
 - R6.6.** Responding to IROL and SOL violations.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

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December 27, 2004–
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February 8, 2005
April 1, 2005

A. Introduction

- 1. Title:** Reporting System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) Violations
- 2. Number:** TOP-007-0
- 3. Purpose:**
This standard ensures SOL and IROL violations are being reported to the Reliability Coordinator so that the Reliability Coordinator may evaluate actions being taken and direct additional corrective actions as needed.
- 4. Applicability:**
 - 4.1.** Transmission Operators.
 - 4.2.** Reliability Coordinators.
- 5. Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** A Transmission Operator shall inform its Reliability Coordinator when an IROL or SOL has been exceeded and the actions being taken to return the system to within limits.
- R2.** Following a Contingency or other event that results in an IROL violation, the Transmission Operator shall return its transmission system to within IROL as soon as possible, but not longer than 30 minutes.
- R3.** A Transmission Operator shall take all appropriate actions up to and including shedding firm load, or directing the shedding of firm load, in order to comply with Requirement R2.
- R4.** The Reliability Coordinator shall evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits.

C. Measures

- M1.** Evidence that the Transmission Operator informed the Reliability Coordinator when an IROL or SOL was exceeded and the actions taken to return the system to within limits.
- M2.** Evidence that the Transmission Operator returned the system to within IROL within 30 minutes for each incident that an IROL, or SOL that became an IROL due to changed system conditions, was exceeded.
- M3.** Evidence that the Reliability Coordinator evaluated actions and provided direction required to return the system to within limits.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

The Reliability Coordinator shall report any IROL violation exceeding 30 minutes to the Regional Reliability Organization and NERC within 72 hours. Each Regional Reliability Organization shall report any such violations to NERC via the NERC compliance reporting process. The Reliability Coordinator shall report any SOL violation that has become an IROL violation because of changed system conditions; i.e. exceeding the limit will require action to prevent:

- 1.1.1.** System instability.
- 1.1.2.** Unacceptable system dynamic response or equipment tripping.

Standard TOP-007-0 — Reporting SOL and IROL Violations

- 1.1.3. Voltage levels in violation of applicable emergency limits.
- 1.1.4. Loadings on transmission facilities in violation of applicable emergency limits.
- 1.1.5. Unacceptable loss of load based on regional and/or NERC criteria.
- 1.2. **Compliance Monitoring Period and Reset Timeframe**
The reset period is monthly.
- 1.3. **Data Retention**
The data retention period is three months.

2. Levels of Non-Compliance

- 2.1. The Transmission Operator did not inform the Reliability Coordinator of an IROL or an SOL that has become an IROL because of changed system conditions, and the actions they are taking to return the system to within limits, or
- 2.2. The Transmission Operator did not take corrective actions as directed by the Reliability Coordinator to return the system to within the IROL within 30 minutes. (See Table 1-TOP-007-0 below.)
- 2.3. The limit violation was reported to the Reliability Coordinator, who did not provide appropriate direction to the Transmission Operator, resulting in an IROL violation in excess of 30 minutes duration.

Table 1-TOP-007-0 IROL and SOL Reporting Levels of Non-Compliance

Percentage by which IROL or SOL that has become an IROL is exceeded*	Limit exceeded for more than 30 minutes, up to 35 minutes.	Limit exceeded for more than 35 minutes, up to 40 minutes.	Limit exceeded for more than 40 minutes, up to 45 minutes.	Limit exceeded for more than 45 minutes.
Greater than 0%, up to and including 5%	Level 1	Level 2	Level 2	Level 3
Greater than 5%, up to and including 10%	Level 2	Level 2	Level 3	Level 3
Greater than 10%, up to and including 15%	Level 2	Level 3	Level 3	Level 4
Greater than 15%, up to and including 20%	Level 3	Level 3	Level 4	Level 4
Greater than 20%, up to and including 25%	Level 3	Level 4	Level 4	Level 4
Greater than 25%	Level 4	Level 4	Level 4	Level 4

*Percentage used in the left column is the flow measured at the end of the time period (30, 35, 40, or 45 minutes).

E. Regional Differences

None identified.

Version History

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Anticipated Actions

Anticipated Date

- | | |
|---|---------------------------------------|
| 1. Seek endorsement of NERC technical committees. | November 9–11, 2004 |
| 2. First ballot of Version 0 standards. | December 1–10, 2004 |
| 3. Recirculation ballot of Version 0 standards. | December 27, 2004–
January 7, 2005 |
| 4. 30-day posting before board adoption. | January 8, 2005–
February 8, 2005 |
| 5. Board adopts Version 0 standards. | February 8, 2005 |
| 6. Effective date. | April 1, 2005 |

A. Introduction

- 1. Title:** Voltage and Reactive Control
- 2. Number:** VAR-001-0
- 3. Purpose:**

To ensure voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the Interconnection.
- 4. Applicability:**
 - 4.1.** Transmission Operators.
 - 4.2.** Generator Operators
 - 4.3.** Purchasing-Selling Entities
- 5. Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and MVAR flows within their individual areas and with the areas of neighboring Transmission Operators.
- R2.** Each Transmission Operator shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.
- R3.** Each Purchasing-Selling Entity shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by its Transmission Service Provider.
- R4.** The Transmission Operator shall know the status of all transmission reactive power resources, including the status of voltage regulators and power system stabilizers.
- R5.** The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.
- R6.** Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits.
- R7.** Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.
 - R7.1.** Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.
- R8.** Each Transmission Operator shall correct IROL or SOL violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.
- R9.** Each Generator Operator shall provide information to its Transmission Operator on the status of all generation reactive power resources, including the status of voltage regulators and power system stabilizers.

Standard VAR-001-0 — Voltage and Reactive Control

R9.1. When a generator's voltage regulator is out of service, the Generator Operator shall maintain the generator field excitation at a level to maintain Interconnection and generator stability.

R10. The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

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1. SAC approves Version 0 SAR for posting (April 14, 2004).
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6. Drafting Team posts Draft 1 for comment (July 9 to August 9, 2004).
7. JIC assigns Version 0 reliability standards to NERC and business practices to NAESB (August 16, 2004).
8. Drafting Team posts Draft 2 for comment (September 1 to October 15, 2004).

Description of Current Draft:

Draft 3 is to be posted for a 30-day posting prior to balloting the Version 0 standards. This draft includes revisions based on industry comments received during the posting of Draft 2. Changes from Draft 2 are highlighted in the redline copy of Draft 3.

Future Development Plan:

Anticipated Actions

1. Seek endorsement of NERC technical committees.
2. First ballot of Version 0 standards.
3. Recirculation ballot of Version 0 standards.
4. 30-day posting before board adoption.
5. Board adopts Version 0 standards.
6. Effective date.

Anticipated Date

November 9–11, 2004
December 1–10, 2004
December 27, 2004–
January 7, 2005
January 8, 2005–
February 8, 2005
February 8, 2005
April 1, 2005

A. Introduction

1. Title: Interchange Transaction Tagging

2. Number: INT-001-0

3. Purpose:

To ensure that Interchange Transactions, certain Interchange Schedules, and intra-Balancing Authority Area transfers using Point-to-Point Transmission Service are Tagged in adequate time to allow the transactions to be assessed for reliability impacts by the affected Reliability Coordinators, Transmission Service Providers, and Balancing Authorities, and to allow adequate time for implementation.

4. Applicability:

4.1. Purchase-Selling Entities.

4.2. Balancing Authorities.

5. Proposed Effective Date: April 1, 2005

B. Requirements

R1. The Load-serving Purchasing-Selling Entity shall be responsible for ensuring Tags are submitted for:

R1.1. All Interchange Transactions that are between Balancing Authority Areas

R1.2. All transfers that are entirely within a Balancing Authority Area using Point-to-Point Transmission Service (including all grandfathered and “non-Order 888” Point-to-Point Transmission Service).

R1.3. All Dynamic Schedules at the expected average MW profile for each hour.

R2. The Sink Balancing Authority shall be responsible for ensuring a Tag is provided:

R2.1. If a Purchasing-Selling Entity is not involved in the Transaction, such as delivery from a jointly owned generator.

R2.2. To replace unexpected generation loss, such as through prearranged reserve sharing agreements or other arrangements. If the duration of the Emergency Transaction to replace the generation loss is less than 60 minutes, then the Transaction shall be exempt from Tagging.

R2.3. All bilateral inadvertent interchange payback.

R3. The Purchasing Selling Entity responsible for submitting the Tag shall submit all Tags to the Sink Balancing Authority according to timing tables in Attachment 1-INT-001-0.

R4. The Balancing Authority or Purchasing-Selling Entity responsible for submitting the Tag shall include the reliability data listed in Attachment 2-INT-001-0 in the Tag.

R5. Each Purchasing-Selling Entity with title to an Interchange Transaction shall have, or shall arrange to have, personnel directly and immediately available for notification of Interchange Transaction changes. These personnel shall be available from the time that the title to the Interchange Transaction is acquired until the Interchange Transaction has been completed.

C. Measures

M1. A Balancing Authority shall provide documentation to show all scheduled interchanges between Balancing Authority Areas were Tagged.

D. Compliance

Standard INT-001-0 — Interchange Transaction Tagging

Not Specified.

E. Regional Differences

1. [WECC Tagging Dynamic Schedules and Inadvertent Payback Waiver](#) effective on November 21, 2002.
2. [MISO Energy Flow Information Waiver](#) effective on July 16, 2003.

Version History

Version	Date	Action	Change Tracking
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Attachment 1-INT-001-0 — Tag Submission and Response Timetables for New Transactions

Eastern Interconnection – New Transactions

The table below represents the Tag submission and assessment deadlines within the Eastern Interconnection. These are default requirements; some regulatory or provincially-approved provider practices may have requirements that are more stringent. Under these instances, the more restrictive criteria shall be adhered to. The table describes the various minimum submission and assessment timing requirements.

Table 1: Eastern Interconnection – Timing Requirements

Transaction Duration	PSE Submit Deadline*	Actual Tag Submission Time	Provider Assessment Time	Time to Start of Transaction
Less than 24 Hours	20 Minutes prior to start	≤1 Hour prior to start	≤ 10 Minutes from Tag receipt	≥ 10 Min
		>1 to <4 hours prior to start	≤20 Minutes from Tag receipt	≥ 40 Min
		≥ 4 Hours prior to start	≤ 2 Hours from Tag receipt	≥ 2 Hours
24 Hours or longer	4 Hours prior to start	Any	≤ 2 Hours from Tag receipt	≥ 2 Hours
*Start time references are for start of the Transaction not the start of the Ramp.				

Tag submission timing requirements are based on the duration of the Transaction. Tags representing Transactions that run for less than one day (24 hours) must be submitted at least 20 minutes prior to the start of the Transaction (excluding Ramp time). Tags representing Transactions running for one day or more (24 hours or more) must be submitted at least four hours prior to the start. Tags submitted that meet these requirements shall be considered “on-time” and may be granted conditional approval. Tags submitted that do not meet these requirements shall be considered “late,” and consequently will be denied if not explicitly approved by all parties.

Tag assessment timing requirements are based on the submission time of the Tag, as well as the duration. Hourly Tags submitted one hour or less prior to start must be evaluated in ten minutes. Hourly Tags submitted more than one hour but less than four hours prior to start must be evaluated in 20 minutes. Tags of a duration less than 24 hours that are submitted four hours or more prior to start must be evaluated in two hours. Tags of duration 24 hours or more must be evaluated in two hours.

1) Eastern Interconnection — Reallocation During a Transmission Loading Relief (TLR) Event

During a NERC TLR event, Transactions may be submitted to replace existing Transactions with a lower transmission priority. The new Transaction Tag must be received no later than 35 minutes prior to the top of the hour to allow time for Reliability Coordinator to assess the impact of reallocation.

Standard INT-001-0 — Interchange Transaction Tagging

Western Interconnection – New Transactions

The table below represents the Tag submission and assessment deadlines within the Western Interconnection. These are default requirements. The tables describe the various minimum submission and assessment timing requirements.

Table 2: Western Interconnection – Timing Requirements

Transaction Start/Submittal Time	Late Status Deadline	Actual Tag Submission Time*	Provider Assessment Time	Approval/Denial Notes	Time to Start of Transaction*
Start 00:00 next day or beyond when submitted prior to 18:00 of the current day	15:00 day prior to start	Any	3 hours	Passive approval if submitted before deadline, else passive denial. Deferred denial	≥ 6 Hours
Start 00:00 next day and submitted between 18:00 and 23:59:59 on day prior to start – OR – start within current day		≥ 4 Hours prior to start	2 Hours from Tag receipt	Passive approval Deferred denial	≥ 2 Hours
		<4 Hours to ≥1 Hour prior to start	20 minutes from Tag receipt	Passive approval Deferred denial	≥ 40 Min
		<1 hour to ≥30 minutes prior to start	10 minutes from Tag receipt	Passive approval Deferred denial	≥ 20 Min
		<30 minutes to ≥20 minutes prior to start	10 minutes from Tag receipt	Passive approval Deferred denial	≥ 10 Min
	20 minutes prior to start	<20 minutes prior to start	5 minutes from Tag receipt	Passive denial. Deferred denial	Submission time minus maximum time of 5 minutes

Notes/Clarification:

All clock times are in Pacific Prevailing Time (PPT).

Tags falling under the criteria in the first row are deemed pre-schedule Tags.

Tags falling under the criteria in the remaining rows are deemed real-time Tags.

Pre-schedule Tags submitted between 15:00 and 18:00 will be assigned LATE composite status.

Real-time Tags submitted after 20 minutes prior to the start of the Transaction will be assigned LATE composite status.

*Start-time references are for start of the Transaction, not the start of the Ramp.

Tag submission timing requirements are based on the type and duration of the Transaction. Tags representing Transactions that run for less than one day (24 hours) within the current day must be submitted at least 20 minutes prior to the start of the Transaction (excluding Ramp time). Tags representing Transactions that are pre-scheduled to start the next day must be submitted by 1500 PST the day prior to the day the Transaction is to start. Tags submitted that meet these requirements shall be

Standard INT-001-0 — Interchange Transaction Tagging

considered “on-time” and may be granted conditional approval. Tags submitted that do not meet these requirements shall be considered “late,” and consequently will be denied if not explicitly approved by all parties.

Tag assessment timing requirements are based on the submission time of the Tag, as well as the duration. Hourly Tags submitted one hour or less prior to start must be evaluated in ten minutes. Hourly Tags submitted more than one hour but less than four hours prior to start must be evaluated in 20 minutes. Tags of a duration less than 24 hours that are submitted four hours or more prior to start must be evaluated in two hours. Tags submitted for pre-scheduled service starting the next day or a future day must be evaluated in three hours.

Attachment 2-INT-001-0 — Required Tag Data

The following is the reliability information necessary to assess a Transaction:

1. Physical path — the description of physically scheduling parties, always containing a generation segment, at least one transmission segment, and a Load segment.
2. Generation — the physical characteristics of the energy source.
3. Resource service point — the physical point at which the energy is being generated. This may vary in granularity, depending on local practices.
4. Energy profile — energy to be produced by the generator for each time segment of the Transaction.
5. Transmission — the physical characteristics of a wheel (import, export, or through).
6. Transmission Service Provider — the identity of the Transmission Service Provider that is wheeling the energy.
7. Point of receipt — valid point of receipt for scheduled transmission reservation.
8. Point of delivery — valid point of delivery for scheduled transmission reservation.
9. Scheduling entity(ies) — entities that are physically scheduling interchange on behalf of the Transmission Service Provider in order to provide wheeling services. Typically this is the Balancing Authority providing a service for the Transmission Service Provider, but several Balancing Authorities may be supporting a regional transmission service.
10. Loss provision — the manner in which losses are accounted when they are not scheduled as in-kind megawatt distributions through the original transaction or through a separately Tagged transaction.
11. POR and POD profiles — schedule of energy flow imported at the Point of Receipt and Exported at the Point of Delivery.
12. Transmission reservation number — reference to a particular transmission reservation being used to provide transmission capacity to support the transaction being described.
13. Transmission reservation profile — information describing the transmission reservation commitment.
14. Transmission product — the firmness of service associated with the transmission reservation being used.
15. Load — the physical characteristics of the energy sink.
16. Resource service point (sink) — the physical point at which the energy is being consumed. This may vary in granularity, dependent on local practices.
17. Energy profile — energy to be consumed by the Load for this Transaction.
18. Contact information of person representing the Purchasing-Selling Entity responsible for the Tag.

The following information is required to modify a Transaction:

19. The Transaction being curtailed or reloaded.
20. All necessary profile changes to set the maximum flow allowed for the transaction during the appropriate hours.
21. A contact person that initiated the curtailment or reload.

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAC approves Version 0 SAR for posting (April 14, 2004).
2. SAC approves *Plan for Accelerating Adoption of NERC Reliability Standards* (April 19, 2004).
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6. Drafting Team posts Draft 1 for comment (July 9 to August 9, 2004).
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8. Drafting Team posts Draft 2 for comment (September 1 to October 15, 2004).

Description of Current Draft:

Draft 3 is to be posted for a 30-day posting prior to balloting the Version 0 standards. This draft includes revisions based on industry comments received during the posting of Draft 2. Changes from Draft 2 are highlighted in the redline copy of Draft 3.

Future Development Plan:

Anticipated Actions

Anticipated Date

- | | |
|---|---------------------------------------|
| 1. Seek endorsement of NERC technical committees. | November 9–11, 2004 |
| 2. First ballot of Version 0 standards. | December 1–10, 2004 |
| 3. Recirculation ballot of Version 0 standards. | December 27, 2004–
January 7, 2005 |
| 4. 30-day posting before board adoption. | January 8, 2005–
February 8, 2005 |
| 5. Board adopts Version 0 standards. | February 8, 2005 |
| 6. Effective date. | April 1, 2005 |

A. Introduction

1. Title: Interchange Transaction Tag Communication and Reliability Assessment

2. Number: INT-002-0

3. Purpose:

To ensure that Interchange Transaction information is provided to all entities needing to make reliability assessments and to ensure all affected reliability entities assess the reliability impacts of Interchange Transactions before approving or denying a Tag. To communicate the approvals and denials of the Tag and the final composite status of the Tag.

4. Applicability:

4.1. Balancing Authorities

4.2. Transmission Service Providers

5. Proposed Effective Date: April 1, 2005

B. Requirements

R1. The Sink Balancing Authority shall ensure that all Tags and any modifications to Tags are provided via a secure network to the following entities on the Scheduling Path:

R1.1. Sink and Source Balancing Authority for the Transaction.

R1.2. Intermediate Balancing Authorities on the Schedule Path.

R1.3. Transmission Service Provider(s) on the Schedule Path.

R1.4. Reliability analysis services (IDC or other regional reliability tools).

R1.5. Transmission Operators and Reliability Coordinators who may receive the information through Reliability analysis services.

R2. Transmission Service Providers on the Scheduling Path shall be responsible for assessing and approving or denying the Interchange Transaction based on established reliability criteria and adequacy of Interconnected Operating Services and transmission rights as well as the reasonableness of the Interchange Transaction Tag. The Transmission Service Provider shall verify and assess:

R2.1. Valid OASIS reservation number or transmission contract identifier.

R2.2. Transmission priority matches reservation.

R2.3. Energy profile fits within OASIS reservation.

R2.4. OASIS reservation accommodates all Interchange Transactions.

R2.5. Connectivity of adjacent Transmission Service Providers.

R2.6. Loss accounting.

R3. Balancing Authorities on the Scheduling Path shall be responsible for assessing and approving or denying the Interchange Transaction. The Balancing Authority shall verify and assess:

R3.1. Transaction start and end time.

R3.2. Energy profile (ability to support the magnitude of the transaction).

R3.3. Ramp (ability of generation maneuverability to accommodate).

R3.4. Scheduling path (proper connectivity of adjacent Balancing Authorities).

- R4.** Each Balancing Authority and Transmission Service Provider on the Scheduling Path shall communicate their approval or denial of the Interchange Transaction to the Sink Balancing Authority.
- R5.** Upon receipt of approvals or denials from all of the individual Balancing Authorities and Transmission Service Providers, the Sink Balancing Authority shall communicate the composite approval status of the Interchange Transaction to the Purchasing-Selling Entity and all other Balancing Authorities and Transmission Service Providers on the Scheduling Path and through the Reliability analysis service to affected Transmission Operators and Reliability Coordinators.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

1. [MISO Scheduling Agent Waiver](#) dated November 21, 2002.
2. [MISO Enhanced Scheduling Agent Waiver](#) dated July 16, 2003.

Version History

Version	Date	Action	Change Tracking
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Standard Development Roadmap

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Future Development Plan:

Anticipated Actions	Anticipated Date
1. Seek endorsement of NERC technical committees.	November 9-11, 2004
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3. Recirculation ballot of Version 0 standards.	December 27, 2004– January 7, 2005
4. 30-day posting before board adoption.	January 8, 2005– February 8, 2005
5. Board adopts Version 0 standards.	February 8, 2005
6. Effective date.	April 1, 2005

A. Introduction

1. Title: Interchange Transaction Implementation

2. Number: INT-003-0

3. Purpose:

To ensure Balancing Authorities confirm Interchange Schedules with Adjacent Balancing Authorities prior to implementing the schedules in their Area Control Error (ACE) equations. To ensure Balancing Authorities incorporate all confirmed Schedules into their ACE equations.

4. Applicability

4.1. Balancing Authorities.

5. Proposed Effective Date: April 1, 2005

B. Requirements

R1. Each Receiving Balancing Authority shall confirm Interchange Schedules with the Sending Balancing Authority prior to implementation in the Balancing Authority's ACE equation.

R1.1. The Sending Balancing Authority and Receiving Balancing Authority shall agree on:

R1.1.1. Interchange Schedule start and end time.

R1.1.2. Energy profile.

R1.1.3. Ramp start time and duration (Balancing Authorities shall use the Ramp duration established for their Interconnection unless they agree to an alternative Ramp duration.) Default Ramps durations are as follows:

- Default Ramp duration for the Eastern Interconnection shall be 10 minutes equally across the Interchange Schedule start and end times.
- Default Ramp duration for the Western Interconnection shall be 20 minutes equally across the Interchange Schedule start and end times.
- 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 than the above defaults, but must be identical for the Sending Balancing Authority and Receiving Balancing Authority.

R1.2. If a high voltage direct current (HVDC) tie is on the Scheduling Path, then the Sending Balancing Authorities and Receiving Balancing Authorities shall coordinate the Interchange Schedule with the Transmission Operator of the HVDC tie.

R1.3. Balancing Authorities that implement Interchange Schedules that cross an Interconnection boundary shall use the same start time and Ramp durations.

R2. Balancing Authorities shall implement Interchange Schedules only with Adjacent Balancing Authorities.

R3. Balancing Authorities shall begin and end Interchange Schedules at a time agreed to by the Source Balancing Authority, Sink Balancing Authority, and Intermediate Balancing Authorities.

R4. The Sink Balancing Authority shall be responsible for initiating implementation of each Interchange Transaction as tagged. Upon receiving composite approval from the Sink

Standard INT-003-0 – Interchange Transaction Implementation

Balancing Authority, each Balancing Authority on the scheduling path shall enter confirmed Schedules into its Automatic Generation Control ACE equation.

- R5.** Balancing Authorities shall operate such that Interchange Schedules do not knowingly cause any other systems to violate established operating criteria.
- R6.** Balancing Authorities shall operate such that the maximum Net Interchange Schedule between any two Balancing Authorities does not exceed the lesser of:
 - R6.1.** The total capacity of both the owned and arranged-for transmission facilities in service for any Transmission Service Provider along the path, or
 - R6.2.** The established network Total Transfer Capability between Balancing Authorities, which considers other transmission facilities available to them under specific arrangements, and the overall physical constraints of the transmission network.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

1. [MISO Scheduling Agent Waiver](#) dated November 21, 2002.
2. [MISO Enhanced Scheduling Agent Waiver](#) dated July 16, 2003.
3. [MISO Energy Flow Information Waiver](#) dated July 16, 2003.

Version History

Version	Date	Action	Change Tracking
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Standard Development Roadmap

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Anticipated Actions

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6. Effective date.

Anticipated Date

November 9–11, 2004
December 1–10, 2004
December 27, 2004–
January 7, 2005
January 8, 2005–
February 8, 2005
February 8, 2005
April 1, 2005

A. Introduction

1. **Title:** **Interchange Transaction Modifications**
2. **Number:** INT-004-0
3. **Purpose:** To allow modifications to Interchange Transactions to address potential or actual System Operating Limit (SOL) or Interconnection Reliability Operating Limit (IROL) violations or other reliability conditions. To ensure Dynamic Transfers are adequately tagged to be able to determine their reliability impacts.
4. **Applicability**
 - 4.1. Balancing Authorities
 - 4.2. Reliability Coordinators
 - 4.3. Transmission Operators
 - 4.4. Purchasing-Selling Entities
5. **Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** If a Reliability Coordinator, Transmission Operator, or Source or Sink Balancing Authority, due to a reliability event, needs to modify an Interchange Transaction that is in progress or scheduled to be started, the entity shall, within 60 minutes of the start of the emergency Transaction, modify the Interchange Transaction tag, and shall communicate the modification to the Sink Balancing Authority. Reliability events may include:
 - R1.1.** Transmission Loading Relief procedure curtailment — Eastern Interconnection.
 - R1.2.** Interconnection, regional, or local overload relief or congestion management procedures.
 - R1.3.** SOL or IROL potential or actual limit violation.
 - R1.4.** Loss of generation.
 - R1.5.** Loss of Load.
- R2.** A Generator Operator or Load Serving Entity may request the Host Balancing Authority to modify an Interchange Transaction due to loss of generation or Load.
 - R2.1.** When a loss of generation necessitates curtailing Interchange Transactions, the Source Balancing Authority shall coordinate the modifications to the appropriate tags.
 - R2.2.** When a loss of Load necessitates curtailing Interchange Transactions, the Sink Balancing Authority shall coordinate the modifications to the appropriate tags.
- R3.** Upon receipt of modification to an Interchange Transaction as described in Requirement R1, the Sink Balancing Authority (Source Balancing Authority in the case of a loss of generation) shall communicate the modified information about the Interchange Transaction, including its composite approval status, to all Balancing Authorities and Transmission Service Providers on the Transaction path and the Purchasing-Selling Entity responsible for the Transaction.
- R4.** At such time as the reliability event allows for the reloading of the transaction, the entity that initiated the curtailment shall release the limit on the Interchange Transaction tag to allow reloading the transaction and shall communicate the release of the limit to the Sink Balancing Authority.
- R5.** The Purchasing-Selling Entity responsible for tagging a Dynamic Interchange Schedule shall ensure the tag is updated for the next available scheduling hour and future hours when any one of the following occur:

- R5.1.** The average energy profile in an hour is greater than 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than $\pm 10\%$.
- R5.2.** The average energy profile in an hour is less than or equal to 250 MW and in that hour the actual hourly integrated energy deviates from the hourly average energy profile indicated on the tag by more than ± 25 megawatt-hours.
- R5.3.** A Reliability Coordinator or Transmission Operator determines the deviation, regardless of magnitude, to be a reliability concern and notifies the Purchasing-Selling Entity of that determination and the reasons.

C. Measures

- M1.** The Sink Balancing Authority shall provide evidence that the responsible Purchasing-Selling Entity revised a tag when the deviation exceeded the criteria in Requirement R5.

D. Compliance

- 1. Compliance Monitoring Process**
 Periodic tag audit as prescribed by NERC. For the requested time period, the Sink Balancing Authority shall provide the instances when Dynamic Schedule deviation exceeded the criteria in Requirement 5 and shall provide evidence that the responsible Purchasing-Selling Entity submitted a revised tag.
 - 1.1. Compliance Monitoring Responsibility**
 Regional Reliability Organization.
 - 1.2. Compliance Monitoring Period and Reset Timeframe**
 One calendar year without a violation from the time of the violation.
 - 1.3. Data Retention**
 Three months.
 - 1.4. Additional Compliance Information**
 Not specified.
- 2. Levels of Non-Compliance**
 - 2.1. Level 1:** Not specified.
 - 2.2. Level 2:** Not specified.
 - 2.3. Level 3:** Not specified.
 - 2.4. Level 4:** Not specified.

E. Regional Differences

- 1.** [WECC Tagging Dynamic Schedules and Inadvertent Payback Waiver](#) dated November 21, 2002.

Version History

Version	Date	Action	Change Tracking
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Attachment 1-INT-004-0

Interchange Transaction Modifications

Curtailments, reloads, market-initiated modifications, and other Transaction modifications that affect energy profiles must be received by and evaluated within certain times. The following tables describe the submission and evaluation requirements for such changes.

Modification requests received by the deadlines specified below shall be considered “on time,” and are eligible for passive approval. Modification requests received past the deadlines shall be considered “late,” and are considered denied unless explicitly approved by all parties.

Table 1: Eastern Interconnection — Modifications

Modification Type	Requestor Submission Deadline***	Actual Submission Time***	Evaluation Time
Reliability (Curtailments or Reloads)	20 minutes prior to modification start**	Less than 30 minutes to start	10 minutes
		30 minutes or more prior to start	15 minutes
Market — Committed transmission reservation(s) Reductions	N/A	N/A	N/A
Market — Committed transmission reservation(s) Increases, Energy Reductions, Energy Increases*	20 minutes prior to modification start**	Less than 30 minutes to start	10 minutes
		30 minutes or more prior to start	15 minutes
***Start time references are for start of the Transaction not the start of the Ramp.			

Table 2: Western Interconnection — Modifications

Modification Type	Requestor Submission Deadline***	Actual Submission Time***	Evaluation Time
Reliability (Curtailments or Reloads)	25 minutes prior to modification start**	Less than 30 minutes to start	10 minutes
		30 minutes or more prior to start	15 minutes
Market — Committed transmission reservation(s) Reductions	N/A	N/A	N/A
Market — Committed transmission reservation(s)	25 minutes prior to modification start**	Less than 30 minutes to start	10 minutes

Increases, Energy Reductions, Energy Increases*		30 minutes or more prior to start	15 minutes
***Start time references are for start of the Transaction not the start of the Ramp.			

*See Special Exception for Cancellations below.

**If received after deadline, requires active approval or will be passively denied

Special Exception for Cancellations

A cancellation is defined as setting both committed transmission reservation(s) and energy flow to zero for the duration of the Transaction prior to the start of a Transaction but following that Transaction’s approval. In the event that a Purchasing-Selling Entity submitting the tag elects to cancel a Transaction, the following timelines should be utilized:

Table 3: Special Exception for Cancellations Submission and Evaluation Timing

Region	Submission Deadline*	Evaluation Time
Eastern Interconnection	15 minutes prior to transaction start	If received by deadline, no evaluation required. Request is automatically approved.
		If not received by deadline, request is not eligible for special exception for cancellations, and must be processed normally.
Western Interconnection	20 minutes prior to transaction start	If received by deadline, no evaluation required. Request is automatically approved.
		If not by deadline, request is not eligible for special exception for cancellations, and must be processed normally.
*Start time references are for start of the Transaction not the start of the Ramp.		

Standard TOP 006-0 — Monitoring System Conditions

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAC approves Version 0 SAR for posting (April 14, 2004).
2. SAC approves *Plan for Accelerating Adoption of NERC Reliability Standards* (April 19, 2004).
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Description of Current Draft:

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Future Development Plan:

Anticipated Actions

1. Seek endorsement of NERC technical committees.
2. First ballot of Version 0 standards.
3. Recirculation ballot of Version 0 standards.
4. 30-day posting before board adoption.
5. Board adopts Version 0 standards.
6. Effective date.

Anticipated Date

November 9–11, 2004
December 1–10, 2004
December 27, 2004 –
January 7, 2005
January 8, 2005 –
February 8, 2005
February 8, 2005
April 1, 2005

Standard TOP 006-0 — Monitoring System Conditions

A. Introduction

1. **Title:** Monitoring System Conditions
2. **Number:** TOP-006-0
3. **Purpose:**
To ensure critical reliability parameters are monitored in real-time.
4. **Applicability**
 - 4.1. Transmission Operators.
 - 4.2. Balancing Authorities.
 - 4.3. Generator Operators.
 - 4.4. Reliability Coordinators.
5. **Proposed Effective Date:** April 1, 2005

B. Requirements

- R1. Each Transmission Operator and Balancing Authority shall know the status of all generation and transmission resources available for use.
 - R1.1. Each Generator Operator shall inform its Host Balancing Authority and the Transmission Operator of all generation resources available for use.
 - R1.2. Each Transmission Operator and Balancing Authority shall inform the Reliability Coordinator and other affected Balancing Authorities and Transmission Operators of all generation and transmission resources available for use.
- R2. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources.
- R3. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall provide appropriate technical information concerning protective relays to their operating personnel.
- R4. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern.
- R5. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action.
- R6. Each Balancing Authority and Transmission Operator 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.
- R7. Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall monitor system frequency.

C. Measures

Not specified.

D. Compliance

Not specified.

Standard TOP 006-0 — Monitoring System Conditions

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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Standard Development Roadmap

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Future Development Plan:

Anticipated Actions

Anticipated Date

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January 7, 2005 |
| 4. 30-day posting before board adoption. | January 8, 2005 –
February 8, 2005 |
| 5. Board adopts Version 0 standards. | February 8, 2005 |
| 6. Effective date. | April 1, 2005 |

A. Introduction

- 1. Title:** **Operational Reliability Information**
- 2. Number:** TOP-005-0
- 3. Purpose:** To ensure reliability entities have the operating data needed to monitor system conditions within their areas.
- 4. Applicability**
 - 4.1.** Transmission Operators.
 - 4.2.** Balancing Authorities.
 - 4.3.** Reliability Coordinators.
 - 4.4.** Purchasing Selling Entities.
- 5. Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** Each Transmission Operator and Balancing Authority shall provide its Reliability Coordinator with the operating data that the Reliability Coordinator requires to perform operational reliability assessments and to coordinate reliable operations within the Reliability Coordinator Area.
 - R1.1.** Each Reliability Coordinator shall identify the data requirements from the list in Attachment 1-TOP-005-0 “Electric System Reliability Data” and any additional operating information requirements relating to operation of the bulk power system within the Reliability Coordinator Area.
- R2.** As a condition of receiving data from the Interregional Security Network (ISN), each ISN data recipient shall sign the NERC Confidentiality Agreement for “Electric System Reliability Data.”
- R3.** Upon request, each Reliability Coordinator shall, via the ISN or equivalent system, exchange with other Reliability Coordinators operating data that are necessary to allow the Reliability Coordinators to perform operational reliability assessments and coordinate reliable operations. Reliability Coordinators shall share with each other the types of data listed in Attachment 1-TOP-005-0 “Electric System Reliability Data,” unless otherwise agreed to.
- R4.** Upon request, each Balancing Authority and Transmission Operator shall provide to other Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability, the operating data that are necessary to allow these Balancing Authorities and Transmission Operators to perform operational reliability assessments and to coordinate reliable operations. Balancing Authorities and Transmission Operators shall provide the types of data as listed in Attachment 1-TOP-005-0 “Electric System Reliability Data,” unless otherwise agreed to by the Balancing Authorities and Transmission Operators with immediate responsibility for operational reliability.
- R5.** Each Purchasing-Selling Entity shall provide information as requested by its Host Balancing Authorities and Transmission Operators to enable them to conduct operational reliability assessments and coordinate reliable operations.

C. Measures

- M1.** Evidence that the Reliability Coordinator, Balancing Authority, Transmission Operator, and Purchasing-Selling Entity is providing the information required, within the time intervals specified, and in a format agreed upon by the requesting entities.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Self-Certification: Entities shall annually self-certify compliance to the measures as required by its Regional Reliability Organization.

Exception Reporting: Each Region shall report compliance and violations to NERC via the NERC compliance reporting process.

1.2. Compliance Monitoring Period and Reset Timeframe

Periodic Review: Entities will be selected for operational reviews at least every three years. One calendar year without a violation from the time of the violation.

1.3. Data Retention

Not specified.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: Each entity responsible for reporting information under Requirements R1 to R5 is providing the requesting entities with the data required, in specified time intervals and format, but there are problems with consistency of delivery identified in the measuring process that need remedy (e.g., the data is not supplied consistently due to equipment malfunctions, or scaling is incorrect).

2.2. Level 2: N/A.

2.3. Level 3: N/A.

2.4. Level 4: Each entity responsible for reporting information under Requirements R1 to R5 is not providing the requesting entities with data with the specified content, timeliness, or format. The information missing is included in the requesting entity's list of data.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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Attachment 1-TOP-005-0

Electric System Reliability Data

This Attachment lists the types of data that Reliability Coordinators, Balancing Authorities, and Transmission Operators are expected to provide, and are expected to share with each other.

1. The following information shall be updated at least every ten minutes:
 - 1.1. Transmission data. Transmission data for all Interconnections plus all other facilities considered key, from a reliability standpoint:
 - 1.1.1 Status.
 - 1.1.2 MW or ampere loadings.
 - 1.1.3 MVA capability.
 - 1.1.4 Transformer tap and phase angle settings.
 - 1.1.5 Key voltages.
 - 1.2. Generator data.
 - 1.2.1 Status.
 - 1.2.2 MW and MVAR capability.
 - 1.2.3 MW and MVAR net output.
 - 1.2.4 Status of automatic voltage control facilities.
 - 1.3. Operating reserve.
 - 1.3.1 MW reserve available within ten minutes.
 - 1.4. Balancing Authority demand.
 - 1.4.1 Instantaneous.
 - 1.5. Interchange.
 - 1.5.1 Instantaneous actual interchange with each Balancing Authority.
 - 1.5.2 Current Interchange Schedules with each Balancing Authority by individual Interchange Transaction, including Interchange identifiers, and reserve responsibilities.
 - 1.5.3 Interchange Schedules for the next 24 hours.
 - 1.6. Area Control Error and frequency.
 - 1.6.1 Instantaneous area control error.
 - 1.6.2 Clock hour area control error.
 - 1.6.3 System frequency at one or more locations in the Balancing Authority.
2. Other operating information updated as soon as available.
 - 2.1. Interconnection Reliability Operating Limits and System Operating Limits in effect.
 - 2.2. Forecast of operating reserve at peak, and time of peak for current day and next day.
 - 2.3. Forecast peak demand for current day and next day.
 - 2.4. Forecast changes in equipment status.

- 2.5. New facilities in place.
- 2.6. New or degraded special protection systems.
- 2.7. Emergency operating procedures in effect.
- 2.8. Severe weather, fire, or earthquake.
- 2.9. Multi-site sabotage.

Standard Development Roadmap

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Future Development Plan:

Anticipated Actions

Anticipated Date

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| 4. 30-day posting before board adoption. | January 8, 2005–
February 8, 2005 |
| 5. Board adopts Version 0 standards. | February 8, 2005 |
| 6. Effective date. | April 1, 2005 |

A. Introduction

- 1. Title:** **Planned Outage Coordination**
- 2. Number:** TOP 003-0
- 3. Purpose:** Scheduled generator and transmission outages that may affect the reliability of interconnected operations must be planned and coordinated among Balancing Authorities, Transmission Operators, and Reliability Coordinators.
- 4. Applicability**
 - 4.1.** Generator Operators.
 - 4.2.** Transmission Operators.
 - 4.3.** Balancing Authorities.
 - 4.4.** Reliability Coordinators.
- 5. Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** Generator Operators and Transmission Operators shall provide planned outage information.
 - R1.1.** Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements.
 - R1.2.** Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements.
 - R1.3.** Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.
- R2.** Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate 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., among affected Balancing Authorities and Transmission Operators as required.
- R3.** Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.
- R4.** Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.

C. Measures

- M1.** Evidence that the Generator Operator, Transmission Operator, Balancing Authority, and Reliability Coordinator reported and coordinated scheduled outage information as indicated in the requirements above.

D. Compliance

1. Compliance Monitoring Process

Each Regional Reliability Organization shall conduct a review every three years to ensure that each responsible entity has a process in place to provide planned generator and/or bulk transmission outage information to their Reliability Coordinator, and with neighboring Transmission Operators and Balancing Authorities.

Investigation: At the discretion of the Regional Reliability Organization or NERC, an investigation may be initiated to review the planned outage process of a monitored entity due to a complaint of non-compliance by another entity. Notification of an investigation must be made by the Regional Reliability Organization to the entity being investigated as soon as possible, but no later than 60 days after the event. The form and manner of the investigation will be set by NERC and/or the Regional Reliability Organization.

1.1. Compliance Monitoring Responsibility

A Reliability Coordinator makes a request for an outage to “not be taken” because of a reliability impact on the grid and the outage is still taken. The Reliability Coordinator must provide all its documentation within three business days to the Regional Reliability Organization. Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year without a violation from the time of the violation.

1.3. Data Retention

One calendar year.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: Each entity responsible for reporting information under Requirements R1 and R3 has a process in place to provide information to their Reliability Coordinator but does not have a process in place (where permitted by legal agreements) to provide this information to the neighboring Balancing Authority or Transmission Operator.

2.2. Level 2: N/A.

2.3. Level 3: N/A.

2.4. Level 4: There is no process in place to exchange outage information, or the entity responsible for reporting information under Requirements R1 to R3 does not follow the directives of the Reliability Coordinator to cancel or reschedule an outage.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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Standard Development Roadmap

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A. Introduction

- 1. Title:** **Planned Outage Coordination**
- 2. Number:** TOP 003-0
- 3. Purpose:** Scheduled generator and transmission outages that may affect the reliability of interconnected operations must be planned and coordinated among Balancing Authorities, Transmission Operators, and Reliability Coordinators.
- 4. Applicability**
 - 4.1.** Generator Operators.
 - 4.2.** Transmission Operators.
 - 4.3.** Balancing Authorities.
 - 4.4.** Reliability Coordinators.
- 5. Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** Generator Operators and Transmission Operators shall provide planned outage information.
 - R1.1.** Each Generator Operator shall provide outage information daily to its Transmission Operator for scheduled generator outages planned for the next day (any foreseen outage of a generator greater than 50 MW). The Transmission Operator shall establish the outage reporting requirements.
 - R1.2.** Each Transmission Operator shall provide outage information daily to its Reliability Coordinator, and to affected Balancing Authorities and Transmission Operators for scheduled generator and bulk transmission outages planned for the next day (any foreseen outage of a transmission line or transformer greater than 100 kV or generator greater than 50 MW) that may collectively cause or contribute to an SOL or IROL violation or a regional operating area limitation. The Reliability Coordinator shall establish the outage reporting requirements.
 - R1.3.** Such information shall be available by 1200 Central Standard Time for the Eastern Interconnection and 1200 Pacific Standard Time for the Western Interconnection.
- R2.** Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate 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., among affected Balancing Authorities and Transmission Operators as required.
- R3.** Each Transmission Operator, Balancing Authority, and Generator Operator shall plan and coordinate scheduled outages of telemetering and control equipment and associated communication channels between the affected areas.
- R4.** Each Reliability Coordinator shall resolve any scheduling of potential reliability conflicts.

C. Measures

- M1.** Evidence that the Generator Operator, Transmission Operator, Balancing Authority, and Reliability Coordinator reported and coordinated scheduled outage information as indicated in the requirements above.

D. Compliance

1. Compliance Monitoring Process

Each Regional Reliability Organization shall conduct a review every three years to ensure that each responsible entity has a process in place to provide planned generator and/or bulk transmission outage information to their Reliability Coordinator, and with neighboring Transmission Operators and Balancing Authorities.

Investigation: At the discretion of the Regional Reliability Organization or NERC, an investigation may be initiated to review the planned outage process of a monitored entity due to a complaint of non-compliance by another entity. Notification of an investigation must be made by the Regional Reliability Organization to the entity being investigated as soon as possible, but no later than 60 days after the event. The form and manner of the investigation will be set by NERC and/or the Regional Reliability Organization.

1.1. Compliance Monitoring Responsibility

A Reliability Coordinator makes a request for an outage to “not be taken” because of a reliability impact on the grid and the outage is still taken. The Reliability Coordinator must provide all its documentation within three business days to the Regional Reliability Organization. Each Regional Reliability Organization shall report compliance and violations to NERC via the NERC Compliance Reporting process.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year without a violation from the time of the violation.

1.3. Data Retention

One calendar year.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: The responsible entity has a process in place to provide information to their Reliability Coordinator but does not have a process in place (where permitted by legal agreements) to provide this information to the neighboring Balancing Authority or Transmission Operator.

2.2. Level 2: N/A.

2.3. Level 3: N/A.

2.4. Level 4: There is no process in place to exchange outage information, or the responsible entity does not follow the directives of the Reliability Coordinator to cancel or reschedule an outage.

E. Regional Differences

None identified.

Version History

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February 8, 2005 |
| 5. Board adopts Version 0 standards. | February 8, 2005 |
| 6. Effective date. | April 1, 2005 |

A. Introduction

1. Title: System Protection Coordination

2. Number: PRC-001-1

3. Purpose:

To ensure system protection is coordinated among operating entities.

4. Applicability

4.1. Balancing Authorities

4.2. Transmission Operators

4.3. Generator Operators

5. Proposed Effective Date: April 1, 2005

B. Requirements

R1. Each Transmission Operator, Balancing Authority, and Generator Operator shall be familiar with the purpose and limitations of protection system schemes applied in its area.

R2. Each Generator Operator and Transmission Operator shall notify reliability entities of relay or equipment failures as follows:

R2.1. If a protective relay or equipment failure reduces system reliability, the Generator Operator shall notify its Transmission Operator and Host Balancing Authority. The Generator Operator shall take corrective action as soon as possible.

R2.2. If a protective relay or equipment failure reduces system reliability, the Transmission Operator shall notify its Reliability Coordinator and affected Transmission Operators and Balancing Authorities. The Transmission Operator shall take corrective action as soon as possible.

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring Transmission Operators and Balancing Authorities.

R4. Each Transmission Operator shall coordinate protection systems on major transmission lines and interconnections with neighboring Generator Operators, Transmission Operators, and Balancing Authorities.

R5. A Generator Operator or Transmission Operator shall coordinate changes in generation, transmission, load or operating conditions that could require changes in the protection systems of others:

R5.1. Each Generator Operator shall notify its Transmission Operator in advance of changes in generation or operating conditions that could require changes in the Transmission Operator's protection systems.

R5.2. Each Transmission Operator shall notify neighboring Transmission Operators in advance of changes in generation, transmission, load, or operating conditions that could require changes in the other Transmission Operators' protection systems.

Standard PRC-001-0 — System Protection Coordination

- R6.** Each Transmission Operator and Balancing Authority shall monitor the status of each Special Protection System in their area, and shall notify affected Transmission Operators and Balancing Authorities of each change in status.

C. Measures

Not specified

D. Compliance

Not specified

E. Regional Differences

None identified.

Version History

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February 8, 2005 |
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| 6. Effective date. | April 1, 2005 |

A. Introduction

1. Title: Reliability Responsibilities and Authorities

2. Number: TOP-001-0

3. Purpose:

To ensure reliability entities have clear decision-making authority and capabilities to take appropriate actions or direct the actions of others to return the transmission system to normal conditions during an emergency.

4. Applicability

4.1. Balancing Authorities

4.2. Transmission Operators

4.3. Generator Operators

4.4. Distribution Providers

4.5. Load Serving Entities

5. Proposed Effective Date: April 1, 2005

B. Requirements

R1. Each Transmission Operator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies.

R2. Each Transmission Operator 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.

R3. Each Transmission Operator, Balancing Authority, and Generator Operator shall comply with reliability directives issued by the Reliability Coordinator, and each Balancing Authority and Generator Operator shall comply with reliability directives issued by the Transmission Operator, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances the Transmission Operator, Balancing Authority or Generator Operator shall immediately inform the Reliability Coordinator or Transmission Operator of the inability to perform the directive so that the Reliability Coordinator or Transmission Operator can implement alternate remedial actions.

R4. Each Distribution Provider and Load Serving Entity shall comply with all reliability directives issued by the Transmission Operator, including shedding firm load, unless such actions would violate safety, equipment, regulatory or statutory requirements. Under these circumstances, the Distribution Provider or Load Serving Entity shall immediately inform the Transmission Operator of the inability to perform the directive so that the Transmission Operator can implement alternate remedial actions.

R5. Each Transmission Operator shall inform its Reliability Coordinator and any other potentially affected Transmission Operators of real time or anticipated emergency conditions, and take actions to avoid, when possible, or mitigate the emergency.

R6. Each Transmission Operator, Balancing Authority, and Generator Operator shall render all available emergency assistance to others as requested, provided that the requesting entity has implemented its comparable emergency procedures, unless such actions would violate safety, equipment, or regulatory or statutory requirements.

- R7.** Each Transmission Operator and Generator Operator shall not remove Bulk Electric System facilities from service if removing those facilities would burden neighboring systems unless:
 - R7.1.** For a generator outage, the Generator Operator shall notify and coordinate with the Transmission Operator. The Transmission Operator shall notify the Reliability Coordinator and other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.
 - R7.2.** For a transmission facility, the Transmission Operator shall notify and coordinate with its Reliability Coordinator. The Transmission Operator shall notify other affected Transmission Operators, and coordinate the impact of removing the Bulk Electric System facility.
 - R7.3.** When time does not permit such notifications and coordination, or when immediate action is required to prevent a hazard to the public, lengthy customer service interruption, or damage to facilities, the Generator Operator shall notify the Transmission Operator, and the Transmission Operator shall notify its Reliability Coordinator and adjacent Transmission Operators, at the earliest possible time.
- R8.** During a system emergency, the Balancing Authority and Transmission Operator shall immediately take action to restore the Real and Reactive Power Balance. If the Balancing Authority or Transmission Operator is unable to restore Real and Reactive Power Balance it shall request emergency assistance from the Reliability Coordinator. If corrective action or emergency assistance is not adequate to mitigate the Real and Reactive Power Balance, then the Reliability Coordinator, Balancing Authority, and Transmission Operator shall implement firm load shedding.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAC approves Version 0 SAR for posting (April 14, 2004).
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Future Development Plan:

Anticipated Actions

Anticipated Date

- | | |
|---|---------------------------------------|
| 1. Seek endorsement of NERC technical committees. | November 9–11, 2004 |
| 2. First ballot of Version 0 standards. | December 1–10, 2004 |
| 3. Recirculation ballot of Version 0 standards. | December 27, 2004–
January 7, 2005 |
| 4. 30-day posting before board adoption. | January 8, 2005–
February 8, 2005 |
| 5. Board adopts Version 0 standards. | February 8, 2005 |
| 6. Effective date. | April 1, 2005 |

A. Introduction

- 1. Title:** **Communication and Coordination**
- 2. Number:** COM-002-0
- 3. Purpose:** To ensure Balancing Authorities, Transmission Operators, and Generator Operators have adequate communications and that these communications capabilities are staffed and available for addressing a real-time emergency condition. To ensure communications by operating personnel are effective.
- 4. Applicability**
 - 4.1.** Reliability Coordinators.
 - 4.2.** Balancing Authorities.
 - 4.3.** Transmission Operators.
 - 4.4.** Generator Operators.
- 5. Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** Each Transmission Operator, Balancing Authority, and Generator Operator shall have communications (voice and data links) with appropriate Reliability Coordinators, Balancing Authorities, and Transmission Operators. Such communications shall be staffed and available for addressing a real-time emergency condition.
- R2.** Each Balancing Authority and Transmission Operator shall notify its Reliability Coordinator, and all other potentially affected Balancing Authorities and Transmission Operators through predetermined communication paths of any condition that could threaten the reliability of its area or when firm load shedding is anticipated. The following information shall be conveyed to others in the Interconnection via an Interconnection-wide telecommunications system:
 - R2.1.** The Balancing Authority is unable to purchase capacity or energy to meet its demand and reserve requirements on a day-ahead or hour-by-hour basis.
 - R2.2.** The Transmission Operator 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 Transmission Operator must prepare for the next Contingency.)
 - R2.3.** The Transmission Operator anticipates initiating a 3% or greater voltage reduction, public appeals for load curtailments, or firm load shedding for other than local problems.
- R3.** Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall issue directives in a clear, concise, and definitive manner; shall ensure the recipient of the directive repeats the information back correctly; and shall acknowledge the response as correct or repeat the original statement to resolve any misunderstandings.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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February 8, 2005 |
| 5. Board adopts Version 0 standards. | February 8, 2005 |
| 6. Effective date. | April 1, 2005 |

A. Introduction

- 1. Title:** **Capacity and Energy Emergencies**
- 2. Number:** EOP-002-0
- 3. Purpose:** To ensure Reliability Coordinators and Balancing Authorities are prepared for capacity and energy emergencies.
- 4. Applicability**
 - a. Balancing Authorities
 - b. Reliability Coordinators
- 5. Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.
- R2.** Each Balancing Authority and Reliability Coordinator shall implement its capacity and energy emergency plan, when required and as appropriate, to reduce risks to the interconnected system.
- R3.** A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.
- R4.** A Reliability Coordinator that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to neighboring areas.
- R5.** A Balancing Authority 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.
- R6.** A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing 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.
- R7.** If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to:
 - R7.1.** Loading all available generating capacity.
 - R7.2.** Deploying all available operating reserve.
 - R7.3.** Interrupting interruptible load and exports.
 - R7.4.** Requesting emergency assistance from other Balancing Authorities.
 - R7.5.** Declaring an Energy Emergency through its Reliability Coordinator; and
 - R7.6.** Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

- R8.** Once the Balancing Authority has exhausted the steps listed in Requirement 7, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:
- R8.1.** Manually shed firm load without delay to return its ACE to zero; and
 - R8.2.** Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0 “Energy Emergency Alert Levels.”
- R9.** A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002-0 “Energy Emergency Alert Levels.” The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.
- R10.** When a Transmission Service 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 Attachment 1-IRO-006-0 “Transmission Loading Relief Procedure” for explanation of Transmission Service Priorities):
- R10.1.** The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002-0.
 - R10.2.** The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed.
 - R10.3.** The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.
 - R10.4.** The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

C. Measures

- M1.** At the discretion of the Regional Reliability Organization or NERC, an investigation may be initiated to review the operation of a Balancing Authority or Reliability Coordinator when they have implemented their Capacity and Energy Emergency plans. Notification of an investigation must be made by the Regional Reliability Organization to the Balancing Authority or Reliability Coordinator being investigated as soon as possible, but no later than 60 days after the event. The Balancing Authority or Reliability Coordinator will be reviewed to determine if their Capacity and Energy Emergency Plans were appropriately followed (for a particular situation, not all of the steps may be effective or required).
- M2.** Evidence will be gathered to determine the level of communication between the Balancing Authority or Reliability Coordinator and other affected areas. An assessment will be made by the investigator(s) as to whether the level and timing of communication of system conditions and actions taken to relieve emergency conditions was acceptable and in conformance with the Capacity and Energy Emergency Plans.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One Calendar year without a violation from the time of the violation.

1.3. Data Retention

Each Balancing Authority and Reliability Coordinator is required to maintain operational data, logs, and voice recordings relevant to the implementation of the Capacity and Energy Emergency Plans for 60 days following the implementation. After an investigation is completed, the Regional Reliability Organization is required to keep the report of the investigation on file for two years.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: N/A.

2.2. Level 2: N/A.

2.3. Level 3: One or more of the actions of the Capacity and Energy Emergency Plans were not implemented resulting in a prolonged abnormal system condition.

2.4. Level 4: One or more of the actions of the Capacity and Energy Emergency Plans were not implemented resulting in a prolonged abnormal system condition and there was a delay or gap in communications.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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**Attachment 1-EOP-002-0
Energy Emergency Alerts**

Introduction

This Attachment provides the procedures by which a Load Serving Entity can obtain capacity and energy when it has exhausted all other options and can no longer provide its customers' expected energy requirements. NERC defines this situation as an "Energy Emergency." NERC assumes that a capacity deficiency will manifest itself as an energy emergency.

The Energy Emergency Alert Procedure is initiated by the Load Serving Entity's Reliability Coordinator, who declares various Energy Emergency Alert levels as defined in Section B, "Energy Emergency Alert Levels," to provide assistance to the Load Serving Entity.

The Load Serving Entity who requests this assistance is referred to as an "Energy Deficient Entity."

NERC recognizes that Transmission Providers are subject to obligations under FERC-approved tariffs and other agreements, and nothing in these procedures should be interpreted as changing those obligations.

A. General Requirements

1. Initiation by Reliability Coordinator. An Energy Emergency Alert may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of a Balancing Authority, or 3) upon the request of a Load Serving Entity.

1.1. Situations for initiating alert. An Energy Emergency Alert may be initiated for the following reasons:

- When the Load Serving Entity is, or expects to be, unable to provide its customers' energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase, or
- The Load Serving Entity cannot schedule the resources due to, for example, Available Transfer Capability (ATC) limitations or transmission loading relief limitations.

2. Notification. A Reliability Coordinator who declares an Energy Emergency Alert shall notify all Balancing Authorities and Transmission Providers in its Reliability Area. The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The Reliability Coordinator shall also notify the other Reliability Coordinators when the alert has ended.

B. Energy Emergency Alert Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual energy emergencies in the Interconnection, NERC has established three levels of Energy Emergency Alerts. The Reliability Coordinators will use these terms when explaining energy emergencies to each other. An Energy Emergency Alert is an emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC reliability standards or power supply contracts.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. Alert 1 — All available resources in use.

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and
- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. Alert 2 — Load management procedures in effect.

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
- Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:
 - Public appeals to reduce demand.
 - Voltage reduction.
 - Interruption of non-firm end use loads in accordance with applicable contracts¹.
 - Demand-side management.
 - Utility load conservation measures.

During Alert 2, Reliability Coordinators, Balancing Authorities, and Energy Deficient Entities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The Energy Deficient Entity shall communicate its needs to other Balancing Authorities and market participants. Upon request from the Energy Deficient Entity, the respective Reliability Coordinator shall post the declaration of the alert level along with the name of the Energy Deficient Entity and, if applicable, its Balancing Authority on the NERC website.

2.2 Declaration period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators, Balancing Authority, and Transmission Providers.

2.3 Sharing information on resource availability. A Balancing Authority and market participants with available resources shall immediately contact the Energy Deficient Entity. This should include the possibility of selling non-firm (recallable) energy out of available Operating Reserves. The Energy Deficient Entity shall notify the Reliability Coordinators of the results.

¹ For emergency, not economic, reasons.

- 2.4 Evaluating and mitigating transmission limitations.** The Reliability Coordinators shall review all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) and transmission loading relief procedures in effect that may limit the Energy Deficient Entity's scheduling capabilities. Where appropriate, the Reliability Coordinators shall inform the Transmission Providers under their purview of the pending Energy Emergency and request that they increase their ATC by actions such as restoring transmission elements that are out of service, reconfiguring their transmission system, adjusting phase angle regulator tap positions, implementing emergency operating procedures, and reviewing generation redispatch options.
- 2.4.1 Notification of ATC adjustments.** Resulting increases in ATCs shall be simultaneously communicated to the Energy Deficient Entity and the market via posting on the appropriate OASIS websites by the Transmission Providers.
- 2.4.2 Availability of generation redispatch options.** Available generation redispatch options shall be immediately communicated to the Energy Deficient Entity by its Reliability Coordinator.
- 2.4.3 Evaluating impact of current transmission loading relief events.** The Reliability Coordinators shall evaluate the impact of any current transmission loading relief events on the ability to supply emergency assistance to the Energy Deficient Entity. This evaluation shall include analysis of system reliability and involve close communication among Reliability Coordinators and the Energy Deficient Entity.
- 2.4.4 Initiating inquiries on reevaluating SOLs and IROLs.** The Reliability Coordinators shall consult with the Balancing Authorities and Transmission Providers in their Reliability Areas about the possibility of reevaluating and revising SOLs or IROLs.
- 2.5 Coordination of emergency responses.** The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses.
- 2.6 Energy Deficient Entity actions.** Before declaring an Alert 3, the Energy Deficient Entity must make use of all available resources. This includes but is not limited to:
- 2.6.1 All available generation units are on line.** All generation capable of being on line in the time frame of the emergency is on line including quick-start and peaking units, regardless of cost.
- 2.6.2 Purchases made regardless of cost.** All firm and non-firm purchases have been made, regardless of cost.
- 2.6.3 Non-firm sales recalled and contractually interruptible loads and demand-side management curtailed.** All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and demand-side management activated within provisions of the agreements.
- 2.6.4 Operating Reserves.** Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

3. Alert 3 — Firm load interruption imminent or in progress.

Circumstances:

- Balancing Authority or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

3.1 Continue actions from Alert 2. The Reliability Coordinators, and the Energy Deficient Entity shall continue to take all actions initiated during Alert 2. If the emergency has not already been posted on the NERC website (see paragraph 2.1), the respective Reliability Coordinators will, at this time, post on the website information concerning the emergency.

3.2 Declaration Period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers.

3.3 Use of Transmission short-time limits. The Reliability Coordinators shall request the appropriate Transmission Providers within their Reliability Area to utilize available short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities into the Energy Deficient Entity.

3.4 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator of the Energy Deficient Entity shall evaluate the risks of revising SOLs and IROLs on the reliability of the overall transmission system. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Balancing Authority or Transmission Operator whose equipment would be affected. The resulting increases in transfer capabilities shall only be made available to the Energy Deficient Entity who has requested an Energy Emergency Alert 3 condition. SOLs and IROLs shall only be revised as long as an Alert 3 condition exists or as allowed by the Balancing Authority or Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.4.1 Energy Deficient Entity obligations. The deficient Balancing Authority or Load Serving Entity must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding.

3.4.2 Mitigation of cascading failures. The Reliability Coordinator shall use its best efforts to ensure that revising SOLs or IROLs would not result in any cascading failures within the Interconnection.

3.5 Returning to pre-emergency Operating Security Limits. Whenever energy is made available to an Energy Deficient Entity such that the transmission systems can be returned to their pre-emergency SOLs or IROLs, the Energy Deficient Entity shall notify its respective Reliability Coordinator and downgrade the alert.

3.5.1 Notification of other parties. Upon notification from the Energy Deficient Entity that an alert has been downgraded, the Reliability Coordinator shall notify the affected

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Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers that their systems can be returned to their normal limits.

3.6 Reporting. Any time an Alert 3 is declared, the Energy Deficient Entity shall submit the report enclosed in this Attachment to its respective Reliability Coordinator within two business days of downgrading or termination of the alert. Upon receiving the report, the Reliability Coordinator shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC website. The Reliability Coordinator shall present this report to the Reliability Coordinator Working Group at its next scheduled meeting.

4. Alert 0 - Termination. When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it shall request of its Reliability Coordinator that the EEA be terminated.

4.1. Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the affected Balancing Authorities and Transmission Operators. The Alert 0 shall also be posted on the NERC website if the original alert was so posted.

C. Energy Emergency Alert 3 Report

A Deficient Balancing Authority or Load Serving Entity declaring an Energy Emergency Alert 3 must complete the following report. Upon completion of this report, it is to be sent to the Reliability Coordinator for review within two business days of the incident.

Requesting Balancing Authority:

Entity experiencing energy deficiency (if different from Balancing Authority):

Date/Time Implemented:

Date/Time Released:

Declared Deficiency Amount (MW):

Total energy supplied by other Balancing Authority during the Alert 3 period:

Conditions that precipitated call for "Energy Deficiency Alert 3":

If “Energy Deficiency Alert 3” had not been called, would firm load be cut? If no, explain:

Explain what action was taken in each step to avoid calling for “Energy Deficiency Alert 3”:

- 1. All generation capable of being on line in the time frame of the energy deficiency was on line (including quick start and peaking units) without regard to cost.**
-
-
-

- 2. All firm and nonfirm purchases were made regardless of cost.**
-
-
-

- 3. All nonfirm sales were recalled within provisions of the sale agreement.**
-
-
-

- 4. Interruptible load was curtailed where either advance notice restrictions were met or the interruptible load was considered part of spinning reserve.**
-
-
-

- 5. Available load reduction programs were exercised (public appeals, voltage reductions, etc.).**

6. Operating Reserves being utilized.

Comments:

Reported By:

Organization:

Title:

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Anticipated Date

November 9–11, 2004
December 1–10, 2004
December 27, 2004 –
January 7, 2005
January 8, 2005 –
February 8, 2005
February 8, 2005
April 1, 2005

A. Introduction

1. **Title:** **Response to Transmission Limit Violations**
2. **Number:** TOP-008-0
3. **Purpose:** To ensure Transmission Operators take actions to mitigate SOL and IROL violations.
4. **Applicability**
 - 4.1. Transmission Operators.
5. **Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** The Transmission Operator experiencing or contributing to an IROL or SOL violation shall take immediate steps to relieve the condition, which may include shedding firm load.
- R2.** Each Transmission Operator shall operate to prevent the likelihood that a disturbance, action, or inaction will result in an IROL or SOL violation in its area or another area of the Interconnection. In instances where there is a difference in derived operating limits, the Transmission Operator shall always operate the Bulk Electric System to the most limiting parameter.
- R3.** The Transmission Operator shall disconnect the affected facility if the overload on a transmission facility or abnormal voltage or reactive condition persists and equipment is endangered. In doing so, the Transmission Operator shall notify its Reliability Coordinator and all neighboring Transmission Operators impacted by the disconnection prior to switching, if time permits, otherwise, immediately thereafter.
- R4.** The Transmission Operator 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 Transmission Operator shall use the results of these analyses to immediately mitigate the SOL violation.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

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December 27, 2004 –
January 7, 2005
January 8, 2005 –
February 8, 2005
February 8, 2005
April 1, 2005

A. Introduction

- 1. Title:** **Disturbance Reporting**
- 2. Number:** EOP-004-0
- 3. Purpose:** Disturbances or unusual occurrences that jeopardize the operation of the Bulk Electric System, or result in system equipment damage or customer interruptions, need to be studied and understood to minimize the likelihood of similar events in the future.
- 4. Applicability**
 - 4.1.** Reliability Coordinators.
 - 4.2.** Balancing Authorities.
 - 4.3.** Transmission Operators.
 - 4.4.** Generator Operators.
 - 4.5.** Load Serving Entities.
 - 4.6.** Regional Reliability Organizations.
- 5. Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** Each Regional Reliability Organization shall establish and maintain a Regional reporting procedure to facilitate preparation of preliminary and final disturbance reports.
- R2.** A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity shall promptly analyze Bulk Electric System disturbances on its system or facilities.
- R3.** A Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity experiencing a reportable incident shall provide a preliminary written report to its Regional Reliability Organization and NERC.
 - R3.1.** The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity shall submit within 24 hours of the disturbance or unusual occurrence either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report form. Events that are not identified until some time after they occur shall be reported within 24 hours of being recognized.
 - R3.2.** Applicable reporting forms are provided in Attachments 022-1 and 022-2.
 - R3.3.** 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 Interconnection Reliability Operating Limit and Preliminary Disturbance Report within 24 hours. In such cases, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall promptly notify its Regional Reliability Organization(s) and NERC, and verbally provide as much information as is available at that time. The affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall then provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report.
 - R3.4.** If, in the judgment of the Regional Reliability Organization, after consultation with the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity in which a disturbance occurred, a final report is required, the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity shall prepare this report within

Standard EOP-004-0 — Disturbance Reporting

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 Reliability Organization approval.

- R4.** When a Bulk Electric System disturbance occurs, the Regional Reliability Organization shall make its representatives on the NERC Operating Committee and Disturbance Analysis Working Group available to the affected Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, or Load Serving Entity immediately affected by the disturbance for the purpose of providing any needed assistance in the investigation and to assist in the preparation of a final report.
- R5.** The Regional Reliability Organization 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 Reliability Organization tracking and review indicates at any time that any recommendation is not being acted on with sufficient diligence, the Regional Reliability Organization shall notify the NERC Planning Committee and Operating Committee of the status of the recommendation(s) and the steps the Regional Reliability Organization has taken to accelerate implementation.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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Attachment 1-EOP-004-0 NERC Disturbance Report Form

Introduction

These disturbance reporting requirements apply to all Reliability Coordinators, Balancing Authorities, Transmission Operators, Generator Operators, and Load Serving Entities, and provide a common basis for all NERC disturbance reporting. The entity on whose system a reportable disturbance occurs shall notify NERC and its Regional Reliability Organization of the disturbance using the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report forms. Reports can be sent to NERC via email (info@nerc.com) or by facsimile (609-452-9550) using the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report forms. If a disturbance is to be reported to the U.S. Department of Energy also, the responding entity may use the DOE reporting form when reporting to NERC. Note: All Emergency Incident and Disturbance Reports (Schedules 1 and 2) sent to DOE shall be simultaneously sent to NERC, preferably electronically at info@nerc.com.

The NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Reports are to be made for any of the following events:

1. The loss of a bulk power transmission component that significantly affects the integrity of interconnected system operations. Generally, a disturbance report will be required if the event results in actions such as:
 - a. Modification of operating procedures.
 - b. Modification of equipment (e.g. control systems or special protection systems) to prevent reoccurrence of the event.
 - c. Identification of valuable lessons learned.
 - d. Identification of non-compliance with NERC standards or policies.
 - e. Identification of a disturbance that is beyond recognized criteria, i.e. three-phase fault with breaker failure, etc.
 - f. Frequency or voltage going below the under-frequency or under-voltage load shed points.
2. The occurrence of an interconnected system separation or system islanding or both.
3. Loss of generation by a Generator Operator, Balancing Authority, or Load-Serving Entity — 2,000 MW or more in the Eastern Interconnection or Western Interconnection and 1,000 MW or more in the ERCOT Interconnection.
4. Equipment failures/system operational actions which result in the loss of firm system demands for more than 15 minutes, as described below:
 - a. Entities with a previous year recorded peak demand of more than 3,000 MW are required to report all such losses of firm demands totaling more than 300 MW.
 - b. All other entities are required to report all such losses of firm demands totaling more than 200 MW or 50% of the total customers being supplied immediately prior to the incident, whichever is less.
5. Firm load shedding of 100 MW or more to maintain the continuity of the bulk electric system.
6. Any action taken by a Generator Operator, Transmission Operator, Balancing Authority, or Load-Serving Entity that results in:
 - a. Sustained voltage excursions equal to or greater than $\pm 10\%$, or
 - b. Major damage to power system components, or
 - c. Failure, degradation, or misoperation of system protection, special protection schemes, remedial action schemes, or other operating systems that do not require operator intervention,

Standard EOP-004-0 — Disturbance Reporting

which did result in, or could have resulted in, a system disturbance as defined by steps 1 through 5 above.

7. An Interconnection Reliability Operating Limit (IROL) violation as required in reliability standard TOP-007.
8. Any event that the Operating Committee requests to be submitted to Disturbance Analysis Working Group (DAWG) for review because of the nature of the disturbance and the insight and lessons the electricity supply and delivery industry could learn.

NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report

Check here if this is an Interconnection Reliability Operating Limit (IROL) violation report.

1.	Organization filing report.		
2.	Name of person filing report.		
3.	Telephone number.		
4.	Date and time of disturbance. Date:(mm/dd/yy) Time/Zone:		
5.	Did the disturbance originate in your system?	Yes <input type="checkbox"/> No <input type="checkbox"/>	
6.	Describe disturbance including: cause, equipment damage, critical services interrupted, system separation, key scheduled and actual flows prior to disturbance and in the case of a disturbance involving a special protection or remedial action scheme, what action is being taken to prevent recurrence.		
7.	Generation tripped. MW Total List generation tripped		
8.	Frequency. Just prior to disturbance (Hz): Immediately after disturbance (Hz max.): Immediately after disturbance (Hz min.):		
9.	List transmission lines tripped (specify voltage level of each line).		
10.	Demand tripped (MW): Number of affected Customers: Demand lost (MW-Minutes):	FIRM	INTERRUPTIBLE
11.	Restoration time.	INITIAL	FINAL
	Transmission:		
	Generation:		
	Demand:		

Attachment 2-TOP-004-0
U.S. Department of Energy Disturbance Reporting Requirements

Introduction

The U.S. Department of Energy (DOE), under its relevant authorities, has established mandatory reporting requirements for electric emergency incidents and disturbances in the United States. DOE collects this information from the electric power industry on Form EIA-417 to meet its overall national security and Federal Energy Management Agency's Federal Response Plan (FRP) responsibilities. DOE will use the data from this form to obtain current information regarding emergency situations on U.S. electric energy supply systems. DOE's Energy Information Administration (EIA) will use the data for reporting on electric power emergency incidents and disturbances in monthly EIA reports. In addition, the data may be used to develop legislative recommendations, reports to the Congress and as a basis for DOE investigations following severe, prolonged, or repeated electric power reliability problems.

Every Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity must use this form to submit mandatory reports of electric power system incidents or disturbances to the DOE Operations Center, which operates on a 24-hour basis, seven days a week. All other entities operating electric systems have filing responsibilities to provide information to the Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator or Load Serving Entity when necessary for their reporting obligations and to file form EIA-417 in cases where these entities will not be involved. EIA requests that it be notified of those that plan to file jointly and of those electric entities that want to file separately.

Special reporting provisions exist for those electric utilities located within the United States, but for whom Reliability Coordinator oversight responsibilities are handled by electrical systems located across an international border. A foreign utility handling U.S. Balancing Authority responsibilities, may wish to file this information voluntarily to the DOE. Any U.S.-based utility in this international situation needs to inform DOE that these filings will come from a foreign-based electric system or file the required reports themselves.

Form EIA-417 must be submitted to the DOE Operations Center if any one of the following applies (see Table 1-EOP-004-0 — Summary of NERC and DOE Reporting Requirements for Major Electric System Emergencies):

1. Uncontrolled loss of 300 MW or more of firm system load for more than 15 minutes from a single incident.
2. Load shedding of 100 MW or more implemented under emergency operational policy.
3. System-wide voltage reductions of 3 percent or more.
4. Public appeal to reduce the use of electricity for purposes of maintaining the continuity of the electric power system.
5. Actual or suspected physical attacks that could impact electric power system adequacy or reliability; or vandalism, which target components of any security system. Actual or suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability.
6. Actual or suspected cyber or communications attacks that could impact electric power system adequacy or vulnerability.
7. Fuel supply emergencies that could impact electric power system adequacy or reliability.
8. Loss of electric service to more than 50,000 customers for one hour or more.
9. Complete operational failure or shut-down of the transmission and/or distribution electrical system.

The initial DOE Emergency Incident and Disturbance Report (form EIA-417 – Schedule 1) shall be submitted to the DOE Operations Center within 60 minutes of the time of the system disruption.

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Complete information may not be available at the time of the disruption. However, provide as much information as is known or suspected at the time of the initial filing. If the incident is having a critical impact on operations, a telephone notification to the DOE Operations Center (202-586-8100) is acceptable, pending submission of the completed form EIA-417. Electronic submission via an on-line web-based form is the preferred method of notification. However, electronic submission by facsimile or email is acceptable.

An updated form EIA-417 (Schedule 1 and 2) is due within 48 hours of the event to provide complete disruption information. Electronic submission via facsimile or email is the preferred method of notification. Detailed DOE Incident and Disturbance reporting requirements can be found at: http://www.eia.doe.gov/cneaf/electricity/page/form_417.html.

Table 1-EOP-400-0				
Summary of NERC and DOE Reporting Requirements for Major Electric System Emergencies				
Incident No.	Incident	Threshold	Report Required	Time
1	Uncontrolled loss of Firm System Load	≥ 300 MW – 15 minutes or more	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
2	Load Shedding	≥ 100 MW under emergency operational policy	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
3	Voltage Reductions	3% or more – applied system-wide	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
4	Public Appeals	Emergency conditions to reduce demand	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
5	Physical sabotage, terrorism or vandalism	On physical security systems – suspected or real	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
6	Cyber sabotage, terrorism or vandalism	If the attempt is believed to have or did happen	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
7	Fuel supply emergencies	Fuel inventory or hydro storage levels ≤ 50% of normal	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
8	Loss of electric service	≥ 50,000 for 1 hour or more	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
9	Complete operation failure of electrical system	If isolated or interconnected electrical systems suffer total electrical system collapse	EIA – Sch-1 EIA – Sch-2	1 hour 48 hour
All DOE EIA-417 Schedule 1 reports are to be filed within 60-minutes after the start of an incident or disturbance				
All DOE EIA-417 Schedule 2 reports are to be filed within 48-hours after the start of an incident or disturbance				
<i>All entities required to file a DOE EIA-417 report (Schedule 1 & 2) shall send a copy of these reports to NERC simultaneously, but no later than 24 hours after the start of the incident or disturbance.</i>				
Incident No.	Incident	Threshold	Report Required	Time
1	Loss of major system component	Significantly affects integrity of interconnected system operations	NERC Prelim Final report	24 hour 60 day
2	Interconnected system separation or system islanding	Total system shutdown Partial shutdown, separation, or islanding	NERC Prelim Final report	24 hour 60 day
3	Loss of generation	≥ 2,000 – Eastern Interconnection ≥ 2,000 – Western Interconnection ≥ 1,000 – ERCOT Interconnection	NERC Prelim Final report	24 hour 60 day
4	Loss of firm load ≥15-minutes	Entities with peak demand ≥3,000: loss ≥300 MW All others ≥200MW or 50% of total demand	NERC Prelim Final report	24 hour 60 day
5	Firm load shedding	≥100 MW to maintain continuity of bulk system	NERC Prelim Final report	24 hour 60 day
6	System operation or operation actions resulting in:	<ul style="list-style-type: none"> • Voltage excursions ≥10% • Major damage to system components • Failure, degradation, or misoperation of SPS 	NERC Prelim Final report	24 hour 60 day
7	IROL violation	Reliability standard TOP-007.	NERC Prelim Final report	72 hour 60 day
8	As requested by ORS Chairman	Due to nature of disturbance & usefulness to industry (lessons learned)	NERC Prelim Final report	24 hour 60 day
All NERC Operating Security Limit and Preliminary Disturbance reports will be filed within 24 hours after the start of the incident. If an entity must file a DOE EIA-417 report on an incident, which requires a NERC Preliminary report, the Entity may use the DOE EIA-417 form for both DOE and NERC reports.				
<i>Any entity reporting a DOE or NERC incident or disturbance has the responsibility to also notify its Regional Reliability Organization.</i>				

Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAC approves Version 0 SAR for posting (April 14, 2004).
2. SAC approves *Plan for Accelerating Adoption of NERC Reliability Standards* (April 19, 2004).
3. Board approves *Plan for Accelerating Adoption of NERC Reliability Standards* (June 15, 2004).
4. SAC appoints Version 0 Drafting Team (May 7, 2004).
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6. Drafting Team posts Draft 1 for comment (July 9 to August 9, 2004).
7. JIC assigns Version 0 reliability standards to NERC and business practices to NAESB (August 16, 2004).
8. Drafting Team posts Draft 2 for comment (September 1 to October 15, 2004).

Description of Current Draft:

Draft 3 is to be posted for a 30-day posting prior to balloting the Version 0 standards. This draft includes revisions based on industry comments received during the posting of Draft 2. Changes from Draft 2 are highlighted in the redline copy of Draft 3.

Future Development Plan:

Anticipated Actions

1. Seek endorsement of NERC technical committees.
2. First ballot of Version 0 standards.
3. Recirculation ballot of Version 0 standards.
4. 30-day posting before board adoption.
5. Board adopts Version 0 standards.
6. Effective date.

Anticipated Date

November 9–11, 2004
December 1–10, 2004
December 27, 2004 –
January 7, 2005
January 8, 2005 –
February 8, 2005
February 8, 2005
April 1, 2005

A. Introduction

1. **Title:** **Sabotage Reporting**
2. **Number:** CIP-001-0
3. **Purpose:** Disturbances or unusual occurrences, suspected or determined to be caused by sabotage, shall be reported to the appropriate systems, governmental agencies, and regulatory bodies.
4. **Applicability**
 - 4.1. Reliability Coordinators.
 - 4.2. Balancing Authorities.
 - 4.3. Transmission Operators.
 - 4.4. Generator Operators.
 - 4.5. Load Serving Entities.
5. **Proposed Effective Date:** April 1, 2005

B. Requirements

- R1. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities and multi-site sabotage affecting larger portions of the Interconnection.
- R2. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall have procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection.
- R3. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall provide its operating personnel with sabotage response guidelines, including personnel to contact, for reporting disturbances due to sabotage events.
- R4. Each Reliability Coordinator, Balancing Authority, Transmission Operator, Generator Operator, and Load Serving Entity shall establish communications contacts, as applicable, with local Federal Bureau of Investigation (FBI) or Royal Canadian Mounted Police (RCMP) officials and develop reporting procedures as appropriate to their circumstances.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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January 7, 2005 |
| 4. 30-day posting before board adoption. | January 8, 2005 –
February 8, 2005 |
| 5. Board adopts Version 0 standards. | February 8, 2005 |
| 6. Effective date. | April 1, 2005 |

A. Introduction

- 1. Title:** Normal Operations Planning
- 2. Number:** TOP-002-0
- 3. Purpose:** Current operations plans and procedures are essential to being prepared for reliable operations, including response for unplanned events.
- 4. Applicability**
 - 4.1.** Balancing Authority.
 - 4.2.** Transmission Operator.
 - 4.3.** Generation Operator.
 - 4.4.** Load Serving Entity.
 - 4.5.** Transmission Service Provider.
- 5. Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** Each Balancing Authority and Transmission Operator 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 Balancing Authority and Transmission Operator shall be responsible for using available personnel and system equipment to implement these plans to ensure that interconnected system reliability will be maintained.
- R2.** Each Balancing Authority and Transmission Operator shall ensure its operating personnel participate in the system planning and design study processes, so that these studies contain the operating personnel perspective and system operating personnel are aware of the planning purpose.
- R3.** Each Load Serving Entity and Generator Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal operations with its Host Balancing Authority and Transmission Service Provider. Each Balancing Authority and Transmission Service Provider shall coordinate its current-day, next-day, and seasonal operations with its Transmission Operator.
- R4.** Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.
- R5.** Each Balancing Authority and Transmission Operator shall plan to meet scheduled system configuration, generation dispatch, interchange scheduling and demand patterns.
- R6.** Each Balancing Authority and Transmission Operator shall plan to meet unscheduled changes in system configuration and generation dispatch (at a minimum N-1 Contingency planning) in accordance with NERC, Regional Reliability Organization, subregional, and local reliability requirements.
- R7.** Each Balancing Authority shall plan to meet capacity and energy reserve requirements, including the deliverability/capability for any single Contingency.
- R8.** Each Balancing Authority shall plan to meet voltage and/or reactive limits, including the deliverability/capability for any single contingency.

- R9.** Each Balancing Authority shall plan to meet Interchange Schedules and ramps.
- R10.** Each Balancing Authority and Transmission Operator shall plan to meet all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs).
- R11.** The Transmission Operator shall perform seasonal, next-day, and current-day Bulk Electric System studies to determine SOLs. Neighboring Transmission Operators shall utilize identical SOLs for common facilities. The Transmission Operator shall update these Bulk Electric System studies as necessary to reflect current system conditions; and shall make the results of Bulk Electric System studies available to the Transmission Operators, Balancing Authorities (subject confidentiality requirements), and to its Reliability Coordinator.
- R12.** The Transmission Service Provider 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 Total Transfer Capability and Available Transfer Capability calculation processes.
- R13.** At the request of the Balancing Authority or Transmission Operator, a Generator Operator shall perform generating real and reactive 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 Balancing Authority or Transmission Operator operating personnel as requested.
- R14.** Generator Operators shall, without any intentional time delay, notify their Balancing Authority and Transmission Operator of changes in capabilities and characteristics including but not limited to:
 - R14.1.** Changes in real and reactive output capabilities.
 - R14.2.** Automatic Voltage Regulator status and mode setting.
- R15.** Generation Operators shall, at the request of the Balancing Authority or Transmission Operator, provide a forecast of expected real power output to assist in operations planning (e.g., a seven-day forecast of real output).
- R16.** Subject to standards of conduct and confidentiality agreements, Transmission Operators shall, without any intentional time delay, notify their Reliability Coordinator and Balancing Authority of changes in capabilities and characteristics including but not limited to:
 - R16.1.** Changes in transmission facility status.
 - R16.2.** Changes in transmission facility rating.
- R17.** Balancing Authorities and Transmission Operators shall, without any intentional time delay, communicate the information described in the requirements R1 to R16 above to their Reliability Coordinator.
- R18.** Neighboring Balancing Authorities, Transmission Operators, Generator Operators, Transmission Service Providers and Load Serving Entities shall use uniform line identifiers when referring to transmission facilities of an interconnected network.
- R19.** Each Balancing Authority and Transmission Operator shall maintain accurate computer models utilized for analyzing and planning system operations.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

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February 8, 2005 |
| 5. Board adopts Version 0 standards. | February 8, 2005 |
| 6. Effective date. | April 1, 2005 |

A. Introduction

- 1. Title:** **Emergency Operations Planning**
- 2. Number:** EOP-001-0
- 3. Purpose:** Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.
- 4. Applicability**
 - 4.1.** Balancing Authorities.
 - 4.2.** Transmission Operators.
- 5. Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.
- R2.** The Transmission Operator shall have an emergency load reduction plan for all identified IROLs. The plan shall include the details on how the Transmission Operator 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.
- R3.** Each Transmission Operator and Balancing Authority shall:
 - R3.1.** Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.
 - R3.2.** Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.
 - R3.3.** Develop, maintain, and implement a set of plans for load shedding.
 - R3.4.** Develop, maintain, and implement a set of plans for system restoration.
- R4.** Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:
 - R4.1.** Communications protocols to be used during emergencies.
 - R4.2.** A 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.
 - R4.3.** The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.
 - R4.4.** Staffing levels for the emergency.
- R5.** Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001-0 when developing an emergency plan.

- R6.** The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.
- R7.** The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:
 - R7.1.** The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.
 - R7.2.** The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.
 - R7.3.** The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)
 - R7.4.** The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

C. Measures

- M1.** The Transmission Operator and Balancing Authority shall have its emergency plans available for review by the Regional Reliability Organization at all times.
- M2.** The Transmission Operator and Balancing Authority shall have its two most recent annual self-assessments available for review by the Regional Reliability Organization at all times.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframes

The Regional Reliability Organization shall review and evaluate emergency plans every three years to ensure that the plans consider the applicable elements of Attachment 1-EOP-001-0.

The Regional Reliability Organization may elect to request self-certification of the Transmission Operator and Balancing Authority in years that the full review is not done.

Reset: one calendar year.

1.3. Data Retention

Current plan available at all times.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

- 2.1. Level 1:** One of the applicable elements of Attachment 1-EOP-001-0 has not been addressed in the emergency plans.

Standard EOP-001-0 — Emergency Operations Planning

- 2.2. **Level 2:** Two of the applicable elements of Attachment 1-EOP-001-0 have not been addressed in the emergency plans.
- 2.3. **Level 3:** Three of the applicable elements of Attachment 1-EOP-001-0 have not been addressed in the emergency plans.
- 2.4. **Level 4:** Four or more of the applicable elements of Attachment 1-EOP-001-0 have not been addressed in the emergency plans or a plan does not exist.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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Attachment 1-EOP-001-0

Elements for Consideration in Development of Emergency Plans

1. Fuel supply and inventory — An adequate fuel supply and inventory plan that 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. Notifications to operating entities — Notifications to other operating entities as steps in emergency plan are implemented.

Standard Development Roadmap

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Development Steps Completed:

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Description of Current Draft:

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Future Development Plan:

Anticipated Actions

1. Seek endorsement of NERC technical committees.
2. First ballot of Version 0 standards.
3. Recirculation ballot of Version 0 standards.
4. 30-day posting before board adoption.
5. Board adopts Version 0 standards.
6. Effective date.

Anticipated Date

November 9–11, 2004
December 1–10, 2004
December 27, 2004 –
January 7, 2005
January 8, 2005 –
February 8, 2005
February 8, 2005
April 1, 2005

A. Introduction

- 1. Title:** Load Shedding Plans
- 2. Number:** EOP-003-0
- 3. Purpose:** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.
- 4. Applicability**
 - 4.1.** Transmission Operators.
 - 4.2.** Balancing Authorities.
- 5. Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.
- R2.** Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions.
- R3.** Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected Transmission Operators and Balancing Authorities.
- R4.** A Transmission Operator or Balancing Authority shall consider one or more of these factors in designing an automatic load shedding scheme: frequency, rate of frequency decay, voltage level, rate of voltage decay, or power flow levels.
- R5.** A Transmission Operator or Balancing Authority shall implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.
- R6.** After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.
- R7.** The Transmission Operator and Balancing Authority shall coordinate automatic load shedding throughout their areas with underfrequency isolation of generating units, tripping of shunt capacitors, and other automatic actions that will occur under abnormal frequency, voltage, or power flow conditions.
- R8.** Each Transmission Operator or Balancing Authority shall have plans for operator-controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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Standard Development Roadmap

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Future Development Plan:

Anticipated Actions

Anticipated Date

- | | |
|---|--|
| 1. Seek endorsement of NERC technical committees. | November 9–11, 2004 |
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| 3. Recirculation ballot of Version 0 standards. | December 27, 2004 –
January 7, 2005 |
| 4. 30-day posting before board adoption. | January 8, 2005 –
February 8, 2005 |
| 5. Board adopts Version 0 standards. | February 8, 2005 |
| 6. Effective date. | April 1, 2005 |

A. Introduction

- 1. Title:** System Restoration Plans
- 2. Number:** EOP-005-0
- 3. Purpose:** To ensure plans, procedures, and resources are available to restore the electric system to a normal condition in the event of a partial or total shut down of the system
- 4. Applicability**
 - 4.2.** Transmission Operators.
 - 4.3.** Balancing Authorities.
- 5. Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** Each Transmission Operator shall have a restoration plan to reestablish its electric system in a stable and orderly manner in the event of a partial or total shutdown of its system, including necessary operating instructions and procedures to cover emergency conditions, and the loss of vital telecommunications channels. Each Transmission Operator shall include the applicable elements listed in Attachment 1-EOP-005-0 in developing a restoration plan.
- R2.** Each Transmission Operator shall review and update its restoration plan at least annually and whenever it makes changes in the power system network, and shall correct deficiencies found during the simulated restoration exercises.
- R3.** Each Transmission Operator shall develop restoration plans with a priority of restoring the integrity of the Interconnection.
- R4.** Each Transmission Operator shall coordinate its restoration plans with Balancing Authorities within its area, its Reliability Coordinator, and neighboring Transmission Operators and Balancing Authorities.
- R5.** Each Transmission Operator and Balancing Authority shall periodically test its telecommunication facilities needed to implement the restoration plan.
- R6.** Each Transmission Operator and Balancing Authority shall train its operating personnel in the implementation of the restoration plan. Such training shall include simulated exercises, if practicable.
- R7.** Each Transmission Operator and Balancing Authority shall verify the restoration procedure by actual testing or by simulation.
- R8.** Each Transmission Operator shall ensure the availability and location of black start capability within its area to meet the needs of the restoration plan.
- R9.** Following a disturbance in which one or more areas of the Bulk Electric System become isolated or blacked out, the affected Transmission Operators and Balancing Authorities shall begin immediately to return the Bulk Electric System to normal.
 - R9.1.** The affected Transmission Operators and Balancing Authorities shall work in conjunction with their Reliability Coordinator(s) to determine the extent and condition of the isolated area(s).
 - R9.2.** The affected Transmission Operators and Balancing Authorities shall take the necessary actions to restore Bulk Electric System frequency to normal, including adjusting generation, placing additional generators online, or load shedding.

- R9.3.** The affected Balancing Authorities, working with their Reliability Coordinator(s), shall immediately review the Interchange Schedules between those Balancing Authority Areas or fragments of those Balancing Authority Areas within the separated area and make adjustments as needed to facilitate the restoration. The affected Balancing Authorities shall make all attempts to maintain the adjusted Interchange Schedules, whether generation control is manual or automatic.
- R9.4.** The affected Transmission Operators shall give high priority to restoration of off-site power to nuclear stations.
- R9.5.** The affected Transmission Operators may resynchronize the isolated area(s) with the surrounding area(s) when the following conditions are met:
 - R9.5.1.** Voltage, frequency, and phase angle permit.
 - R9.5.2.** The size of the area being reconnected and the capacity of the transmission lines effecting the reconnection and the number of synchronizing points across the system are considered.
 - R9.5.3.** Reliability Coordinator(s) and adjacent areas are notified and Reliability Coordinator approval is given.
 - R9.5.4.** Load is shed in neighboring areas, if required, to permit successful interconnected system restoration.

C. Measures

Not specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Self-Certification: Each Transmission Operator shall annually self-certify to the Regional Reliability Organization that the following criteria have been met:

- 1.1.1** The necessary operating instructions and procedures for restoring loads, including identification of critical load requirements.
- 1.1.2** A set of procedures for annual review for simulating and, where practical, actual testing and verification of the restoration plan resources and procedures.
- 1.1.3** Documentation must be retained in the personnel training records that operating personnel have been trained annually in the implementation of the plan and have participated in restoration exercises.
- 1.1.4** Any significant changes to the restoration plan must be reported to the Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

The Transmission Operator must have its plan to reestablish its electric system available for a review by the Regional Reliability Organization at all times.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

- 2.1. Level 1:** Plan exists but is not reviewed annually.
- 2.2. Level 2:** Plan exists but does not address one of the elements listed in Attachment 1-EOP-005-0.
- 2.3. Level 3:** N/A.
- 2.4. Level 4:** Plan exists but does not address two or more of the requirements in Attachment 1-EOP-005-0, or there is no restoration plan in place.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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Attachment 1-EOP-005-1

Elements for Consideration in Development of Restoration Plans

The Restoration Plan must consider the following requirements, as applicable:

1. Plan and procedures outlining the relationships and responsibilities of the personnel necessary to implement system restoration.
2. The provision for a reliable black-start capability plan including: fuel resources for black start power for generating units, available cranking and transmission paths, and communication adequacy and protocol and power supplies.
3. The plan must account for the possibility that restoration cannot be completed as expected.
4. The necessary operating instructions and procedures for synchronizing areas of the system that have become separated.
5. The necessary operating instructions and procedures for restoring loads, including identification of critical load requirements.
6. A set of procedures for simulating and, where practical, actually testing and verifying the plan resources and procedures (at least every three years).
7. Documentation must be retained in the personnel training records that operating personnel have been trained annually in the implementation of the plan and have participated in restoration exercises.
8. The functions to be coordinated with and among Reliability Coordinators and neighboring Transmission Operators. (The plan should include references to coordination of actions among neighboring Transmission Operators and Reliability Coordinators when the plans are implemented.)
9. Notification shall be made to other operating entities as the steps of the restoration plan are implemented.

Standard Development Roadmap

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Description of Current Draft:

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Future Development Plan:

Anticipated Actions

Anticipated Date

- | | |
|---|--|
| 1. Seek endorsement of NERC technical committees. | November 9–11, 2004 |
| 2. First ballot of Version 0 standards. | December 1–10, 2004 |
| 3. Recirculation ballot of Version 0 standards. | December 27, 2004 –
January 7, 2005 |
| 4. 30-day posting before board adoption. | January 8, 2005 –
February 8, 2005 |
| 5. Board adopts Version 0 standards. | February 8, 2005 |
| 6. Effective date. | April 1, 2005 |

A. Introduction

1. **Title:** **Plans for Loss of Control Center Functionality**
2. **Number:** EOP-008-0
3. **Purpose:** Each reliability entity must have a plan to continue reliability operations in the event its control center becomes inoperable.
4. **Applicability**
 - 4.1. Transmission Operators.
 - 4.2. Balancing Authorities.
 - 4.3. Reliability Coordinators.
5. **Proposed Effective Date:** April 1, 2005

B. Requirements

- R1. Each Reliability Coordinator, Transmission Operator and Balancing Authority shall have a plan to continue reliability operations in the event its control center becomes inoperable. The contingency plan must meet the following requirements:
 - R1.1. The contingency plan shall not rely on data or voice communication from the primary control facility to be viable.
 - R1.2. The plan shall include procedures and responsibilities for providing basic tie line control and procedures and for maintaining the status of all inter-area schedules, such that there is an hourly accounting of all schedules.
 - R1.3. The contingency plan must address monitoring and control of critical transmission facilities, generation control, voltage control, time and frequency control, control of critical substation devices, and logging of significant power system events. The plan shall list the critical facilities.
 - R1.4. The plan shall include procedures and responsibilities for maintaining basic voice communication capabilities with other areas.
 - R1.5. The plan shall include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan.
 - R1.6. The plan shall include procedures and responsibilities for providing annual training to ensure that operating personnel are able to implement the contingency plans.
 - R1.7. The plan shall be reviewed and updated annually.
 - R1.8. Interim provisions must be included if it is expected to take more than one hour to implement the contingency plan for loss of primary control facility.

C. Measures

- M1. Evidence that the Reliability Coordinator, Transmission Operator or Balancing Authority has developed and documented a current contingency plan to continue the monitoring and operation of the electrical equipment under its control to maintain Bulk Electrical System reliability if its primary control facility becomes inoperable.

D. Compliance

1. **Compliance Monitoring Process**
 - 1.1. **Compliance Monitoring Responsibility**

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

Periodic Review: Review and evaluate the plan for loss of primary control facility contingency as part of the three-year on-site audit process. The audit must include a demonstration of the plan by the Reliability Coordinator, Transmission Operator, and Balancing Authority.

Reset: One calendar year.

1.3. Data Retention

The contingency plan for loss of primary control facility must be available for review at all times.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: NA

2.2. Level 2: A contingency plan has been implemented and tested, but has not been tested in the past year or there are no records of shift operating personnel training.

2.3. Level 3: A contingency plan has been implemented, but does not include all of the elements contained in Requirements 1-4.

2.4. Level 4: A contingency plan has not been developed, implemented, and tested.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
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Standard Development Roadmap

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Future Development Plan:

Anticipated Actions

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2. First ballot of Version 0 standards.
3. Recirculation ballot of Version 0 standards.
4. 30-day posting before board adoption.
5. Board adopts Version 0 standards.
6. Effective date.

Anticipated Date

November 9–11, 2004
December 1–10, 2004
December 27, 2004 –
January 7, 2005
January 8, 2005 –
February 8, 2005
February 8, 2005
April 1, 2005

A. Introduction

- 1. Title:** **Telecommunications**
- 2. Number:** COM-001-0
- 3. Purpose:** Each Reliability Coordinator, Transmission Operator and Balancing Authority needs adequate and reliable telecommunications facilities internally and with others for the exchange of Interconnection and operating information necessary to maintain reliability.
- 4. Applicability**
 - 4.1.** Transmission Operators.
 - 4.2.** Balancing Authorities.
 - 4.3.** Reliability Coordinators.
 - 4.4.** NERCNet User Organizations.
- 5. Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide adequate and reliable telecommunications facilities the exchange of Interconnection and operating information:
 - R1.1.** Internally.
 - R1.2.** Between the Reliability Coordinator and its Transmission Operators and Balancing Authorities.
 - R1.3.** With other Reliability Coordinators, Transmission Operators, and Balancing Authorities as necessary to maintain reliability.
 - R1.4.** Where applicable, these facilities shall be redundant and diversely routed.
- R2.** Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall manage, alarm, test and/or actively monitor vital telecommunications facilities. Special attention shall be given to emergency telecommunications facilities and equipment not used for routine communications.
- R3.** Each Reliability Coordinator, Transmission Operator and Balancing Authority shall provide a means to coordinate telecommunications among their respective areas. This coordination shall include the ability to investigate and recommend solutions to telecommunications problems within the area and with other areas.
- R4.** Unless agreed to otherwise, each Reliability Coordinator, Transmission Operator, and Balancing Authority shall use English as the language for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected Bulk Electric System. Transmission Operators and Balancing Authorities may use an alternate language for internal operations.
- R5.** Each Reliability Coordinator, Transmission Operator, and Balancing Authority shall have written operating instructions and procedures to enable continued operation of the system during the loss of telecommunications facilities.
- R6.** Each NERCNet User Organization shall adhere to the requirements in Attachment 1-COM-001-0, "NERCNet Security Policy."

C. Measures

Not Specified.

D. Compliance

Not specified.

E. Regional Differences

None Identified.

Version History

Version	Date	Action	Change Tracking
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Attachment 1-COM-001-0 — NERCnet Security Policy

Policy Statement

The purpose of this NERCnet Security Policy is to establish responsibilities and minimum requirements for the protection of information assets, computer systems and facilities of NERC and other users of the NERC frame relay network known as “NERCnet.” The goal of this policy is to prevent misuse and loss of assets.

For the purpose of this document, information assets shall be defined as processed or unprocessed data using the NERCnet Telecommunications Facilities including network documentation. This policy shall also apply as appropriate to employees and agents of other corporations or organizations that may be directly or indirectly granted access to information associated with NERCnet.

The objectives of the NERCnet Security Policy are:

- To ensure that NERCnet information assets are adequately protected on a cost-effective basis and to a level that allows NERC to fulfill its mission.
- To establish connectivity guidelines for a minimum level of security for the network.
- To provide a mandate to all Users of NERCnet to properly handle and protect the information that they have access to in order for NERC to be able to properly conduct its business and provide services to its customers.

NERC’s Security Mission Statement

NERC recognizes its dependency on data, information, and the computer systems used to facilitate effective operation of its business and fulfillment of its mission. NERC also recognizes the value of the information maintained and provided to its members and others authorized to have access to NERCnet. It is, therefore, essential that this data, information, and computer systems, and the manual and technical infrastructure that supports it, are secure from destruction, corruption, unauthorized access, and accidental or deliberate breach of confidentiality.

Implementation and Responsibilities

This section identifies the various roles and responsibilities related to the protection of NERCnet resources.

NERCnet User Organizations

Users of NERCnet who have received authorization from NERC to access the NERC network are considered users of NERCnet resources. To be granted access, users shall complete a User Application Form and submit this form to the NERC Telecommunications Manager.

Responsibilities

It is the responsibility of NERCnet User Organizations to:

- Use NERCnet facilities for NERC-authorized business purposes only.
- Comply with the NERCnet security policies, standards, and guidelines, as well as any procedures specified by the data owner.
- Prevent unauthorized disclosure of the data.
- Report security exposures, misuse, or non-compliance situations via Reliability Coordinator Information System or the NERC Telecommunications Manager.

- Protect the confidentiality of all user IDs and passwords.
- Maintain the data they own.
- Maintain documentation identifying the users who are granted access to NERCnet data or applications.
- Authorize users within their organizations to access NERCnet data and applications.
- Advise staff on NERCnet Security Policy.
- Ensure that all NERCnet users understand their obligation to protect these assets.
- Conduct self-assessments for compliance.

User Accountability and Compliance

All users of NERCnet shall be familiar and ensure compliance with the policies in this document.

Violations of the NERCnet Security Policy shall include, but not be limited to any act that:

- Exposes NERC or any user of NERCnet to actual or potential monetary loss through the compromise of data security or damage.
- Involves the disclosure of trade secrets, intellectual property, confidential information or the unauthorized use of data.

Involves the use of data for illicit purposes, which may include violation of any law, regulation or reporting requirement of any law enforcement or government body.

Standard Development Roadmap

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Future Development Plan:

Anticipated Actions

Anticipated Date

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| 1. Seek endorsement of NERC technical committees. | November 9–11, 2004 |
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January 7, 2005 |
| 4. 30-day posting before board adoption. | January 8, 2005 –
February 8, 2005 |
| 5. Board adopts Version 0 standards. | February 8, 2005 |
| 6. Effective date. | April 1, 2005 |

A. Introduction

1. **Title:** **Operating Personnel Responsibility and Authority**
2. **Number:** PER-001-0
3. **Purpose:** Transmission Operator and Balancing Authority operating personnel must have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.
4. **Applicability**
 - 4.1. Transmission Operators.
 - 4.2. Balancing Authorities.
5. **Proposed Effective Date:** April 1, 2005

B. Requirements

- R1. Each Transmission Operator and Balancing Authority shall provide operating personnel with the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System.

C. Measures

- M1. The Transmission Operator and Balancing Authority provide documentation that operating personnel have the responsibility and authority to implement real-time actions to ensure the stable and reliable operation of the Bulk Electric System. These responsibilities and authorities are understood by the operating personnel. Documentation shall include:
 - M1.1 A written current job description that states in clear and unambiguous language the responsibilities and authorities of each operating position of a Transmission Operator and Balancing Authority. The position description identifies personnel subject to the authority of the Transmission Operator and Balancing Authority.
 - M1.2 The current job description is readily accessible in the control room environment to all operating personnel.
 - M1.3 A written current job description that states operating personnel are responsible for complying with the NERC reliability standards.
 - M1.4 Written operating procedures that state that, during normal and emergency conditions, operating personnel have the authority to take or direct timely and appropriate real-time actions. Such actions shall include shedding of firm load to prevent or alleviate System Operating Limit Interconnection or Reliability Operating Limit violations. These actions are performed without obtaining approval from higher-level personnel within the Transmission Operator or Balancing Authority.

D. Compliance

1. Compliance Monitoring Process

Periodic Review: An on-site review including interviews with Transmission Operator and Balancing Authority operating personnel and document verification will be conducted every three years. The job description identifying operating personnel authorities and responsibilities will be reviewed, as will the written operating procedures or other documents delineating the authority of the operating personnel to take actions necessary to maintain the reliability of the Bulk Electric System during normal and emergency conditions.

1.1. Compliance Monitoring Responsibility

Self-certification: The Transmission Operator and Balancing Authority shall annually complete a self-certification form developed by the Regional Reliability Organization based on measures M1.1 to M1.4.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

Permanent.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: The Transmission Operator or Balancing Authority has written documentation that includes three of the four items in M1.

2.2. Level 2: The Transmission Operator or Balancing Authority has written documentation that includes two of the four items in M1.

2.3. Level 3: The Transmission Operator or Balancing Authority has written documentation that includes one of the four items in M1.

2.4. Level 4: The Transmission Operator or Balancing Authority has written documentation that includes none of the items in M1, or the personnel interviews indicate Transmission Operator or Balancing Authority do not have the required authority.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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Standard Development Roadmap

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Future Development Plan:

Anticipated Actions

1. Seek endorsement of NERC technical committees.
2. First ballot of Version 0 standards.
3. Recirculation ballot of Version 0 standards.
4. 30-day posting before board adoption.
5. Board adopts Version 0 standards.
6. Effective date.

Anticipated Date

November 9–11, 2004
December 1–10, 2004
December 27, 2004 –
January 7, 2005
January 8, 2005 –
February 8, 2005
February 8, 2005
April 1, 2005

A. Introduction

- 1. Title:** **Operating Personnel Training**
- 2. Number:** PER-002-0
- 3. Purpose:** Each Transmission Operator and Balancing Authority must provide their personnel with a coordinated training program that will ensure reliable system operation.
- 4. Applicability**
 - 4.1.** Balancing Authority.
 - 4.2.** Transmission Operator.
- 5. Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** Each Transmission Operator and Balancing Authority shall be staffed with adequately trained operating personnel.
- R2.** Each Transmission Operator and Balancing Authority shall have a training program for all operating personnel that are in:
 - R2.1.** Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.
 - R2.2.** Positions directly responsible for complying with NERC standards.
- R3.** For personnel identified in Requirement R2, the Transmission Operator and Balancing Authority shall provide a training program meeting the following criteria:
 - R3.1.** A set of training program objectives must be defined, based on NERC and Regional Reliability Organization standards, entity operating procedures, and applicable regulatory requirements. These objectives shall reference the knowledge and competencies needed to apply those standards, procedures, and requirements to normal, emergency, and restoration conditions for the Transmission Operator and Balancing Authority operating positions.
 - R3.2.** The training program must include a plan for the initial and continuing training of Transmission Operator and Balancing Authority operating personnel. That plan shall address knowledge and competencies required for reliable system operations.
 - R3.3.** The training program must include training time for all Transmission Operator and Balancing Authority operating personnel to ensure their operating proficiency.
 - R3.4.** Training staff must be identified, and the staff must be competent in both knowledge of system operations and instructional capabilities.
- R4.** For personnel identified in Requirement R2, each Transmission Operator and Balancing Authority shall provide its operating personnel at least five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.

C. Measures

- M1.** The Transmission Operator and Balancing Authority operating personnel training program shall be reviewed to ensure that it is designed to promote reliable system operations.

D. Compliance

1. Compliance Monitoring Process

Periodic Review: The Regional Reliability Organization will conduct an on-site review of the Transmission Operator and Balancing Authority operating personnel training program every three years. The operating personnel training records will be reviewed and assessed compared to the program curriculum.

1.1. Compliance Monitoring Responsibility

Self-certification: The Transmission Operator and Balancing Authority will annually provide a self-certification based on Requirements R1 through R4.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar year.

1.3. Data Retention

Three years.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: N/A.

2.2. Level 2: The Transmission Operator or Balancing Authority operating personnel training program does not address all elements of Requirement R3.

2.3. Level 3: The Transmission Operator or Balancing Authority operating personnel training program does not address Requirement R4.

2.4. Level 4: A Transmission Operator or Balancing Authority has not provided a training program for its operating personnel.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAC approves Version 0 SAR for posting (April 14, 2004).
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Future Development Plan:

Anticipated Actions

Anticipated Date

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January 7, 2005 |
| 4. 30-day posting before board adoption. | January 8, 2005 –
February 8, 2005 |
| 5. Board adopts Version 0 standards. | February 8, 2005 |
| 6. Effective date. | April 1, 2005 |

A. Introduction

1. **Title:** **Operating Personnel Credentials**
2. **Number:** PER-003-0
3. **Purpose:** Certification of operating personnel is necessary to ensure minimum competencies for operating a reliable Bulk Electric System.
4. **Applicability**
 - 4.1. Transmission Operators.
 - 4.2. Balancing Authorities.
 - 4.3. Reliability Coordinators.
5. **Proposed Effective Date:** April 1, 2005

B. Requirements

- R1. Each Transmission Operator, Balancing Authority, and Reliability Coordinator shall staff all operating positions that meet both of the following criteria with personnel that are NERC-certified for the applicable functions:
 - R1.1. Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System.
 - R1.2. Positions directly responsible for complying with NERC standards.

C. Measures

- M1. Each Transmission Operator, Balancing Authority, and Reliability Coordinator shall have NERC-certified operating personnel on shift in required positions at all times with the following exceptions:
 - M1.1 While in training, an individual without the proper NERC certification credential may not independently fill a required operating position. Trainees may perform critical tasks only under the direct, continuous supervision and observation of the NERC-certified individual filling the required position.
 - M1.2 During a real-time operating emergency, the time when control is transferred from a primary control center to a backup control center shall not be included in the calculation of non-compliance. This time shall be limited to no more than four hours.

D. Compliance

1. Compliance Monitoring Process

Periodic Review: An on-site review will be conducted every three years. Staffing schedules and certification numbers will be compared to ensure that positions that require NERC-certified operating personnel were covered as required. Certification numbers from the Transmission Operator, Balancing Authority, and Reliability Coordinator will be compared with NERC records.

Exception Reporting: Any violation of the standard must be reported to the Regional Reliability Organization, who will inform the NERC Vice President-Compliance, indicating the reason for the non-compliance and the mitigation plans taken.

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One calendar month without a violation.

1.3. Data Retention

Present calendar year plus previous calendar year staffing plan.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: The Transmission Operator, Balancing Authority, or Reliability Coordinator did not meet the requirement for a total time greater than 0 hours and up to 12 hours during a one calendar month period for each required position in the staffing plan.

2.2. Level 2: The Transmission Operator, Balancing Authority, or Reliability Coordinator did not meet the requirement for a total time greater than 12 hours and up to 36 hours during a one calendar month period for each required position in the staffing plan.

2.3. Level 3: The Transmission Operator, Balancing Authority, or Reliability Coordinator did not meet the requirement for a total time greater than 36 hours and up to 72 hours during a one-month calendar period for each required position in the staffing plan.

2.4. Level 4: The Transmission Operator, Balancing Authority, or Reliability Coordinator did not meet the requirement for a total time greater than 72 hours during a one calendar month period for each required position in the staffing plan.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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Standard Development Roadmap

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Future Development Plan:

Anticipated Actions

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Anticipated Date

November 9–11, 2004
December 1–10, 2004
December 27, 2004–
January 7, 2005
January 8, 2005–
February 8, 2005
February 8, 2005
April 1, 2005

A. Introduction

- 1. Title:** Reliability Coordination – Responsibilities and Authorities
- 2. Number:** IRO-001-0
- 3. Purpose:** Reliability Coordinators must have the authority, plans, and agreements in place to immediately direct reliability entities within their Reliability Coordinator Areas to re-dispatch generation, reconfigure transmission, or reduce load to mitigate critical conditions to return the system to a reliable state. If a Reliability Coordinator delegates tasks to others, the Reliability Coordinator retains its responsibilities for complying with NERC and regional standards. Standards of conduct are necessary to ensure the Reliability Coordinator does not act in a manner that favors one market participant over another.
- 4. Applicability**
 - 4.1.** Reliability Coordinators.
 - 4.2.** Regional Reliability Organizations.
- 5. Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** Each Regional Reliability Organization, subregion, or interregional coordinating group shall establish one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries.
- R2.** The Reliability Coordinator shall comply with a regional reliability plan approved by the NERC Operating Committee.
- R3.** The Reliability Coordinator shall have clear decision-making authority to act and to direct actions to be taken by Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. These actions shall be taken without delay, but no longer than 30 minutes.
- R4.** Reliability Coordinators that delegate tasks to other entities shall have formal operating agreements with each entity to which tasks are delegated. The Reliability Coordinator shall verify that all delegated tasks are understood, communicated, and addressed within its Reliability Coordinator Area. All responsibilities for complying with NERC and regional standards applicable to Reliability Coordinators shall remain with the Reliability Coordinator.
- R5.** The Reliability Coordinator shall list within its reliability plan all entities to which the Reliability Coordinator has delegated required tasks.
- R6.** The Reliability Coordinator shall verify that all delegated tasks are carried out by NERC-certified Reliability Coordinator operating personnel.
- R7.** The Reliability Coordinator shall have clear, comprehensive coordination agreements with adjacent Reliability Coordinators to ensure that System Operating Limit or Interconnection Reliability Operating Limit violation mitigation requiring actions in adjacent Reliability Coordinator Areas are coordinated.
- R8.** Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall comply with Reliability Coordinator directives unless such actions would violate safety, equipment, or regulatory or statutory requirements. Under these circumstances, the Transmission Operator, Balancing Authority, Generator Operator, Transmission Service Provider, Load-Serving Entity, or Purchasing-Selling Entity shall immediately inform the Reliability Coordinator of the inability

Standard IRO-001-0 — Reliability Coordination – Responsibilities and Authorities

to perform the directive so that the Reliability Coordinator may implement alternate remedial actions.

- R9.** The Reliability Coordinator shall act in the interests of reliability for the overall Reliability Coordinator Area and the Interconnection before the interests of any other entity.

C. Measures

- M1.** Documentation must clearly show that the Reliability Coordinator has the authority to immediately direct entities listed in Requirement R8 within its Reliability Coordinator Area to re-dispatch generation, reconfigure transmission, manage interchange transactions, or reduce system demand to mitigate SOL and IROL violations to return the system to a reliable state.

D. Compliance

1. Compliance Monitoring Process

The Regional Reliability Organization shall review the Reliability Coordinator documentation and the agreements with entities listed in Requirement R8 that delineate the authority of the Reliability Coordinator to immediately direct actions of these entities in its Reliability Coordinator Area to mitigate SOL and IROL violations to return the system to a reliable state.

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

One year without a violation from the time of the violation.

1.3. Data Retention

Documentation must be available at all times.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: N/A.

2.2. Level 2: N/A.

2.3. Level 3: Reliability Coordinator does not have documentation demonstrating authority to direct all the entities listed in Requirement R8 within its Reliability Coordinator Area to take actions to mitigate SOL and IROL violations to return the system to a reliable state.

2.4. Level 4: The Reliability Coordinator does not have the authority to direct all the entities listed in Requirement R8 in its Reliability Coordinator Area to take actions to mitigate SOL and IROL violations to return the system to a reliable state.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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Standard Development Roadmap

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Future Development Plan:

Anticipated Actions

Anticipated Date

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| 1. Seek endorsement of NERC technical committees. | November 9–11, 2004 |
| 2. First ballot of Version 0 standards. | December 1–10, 2004 |
| 3. Recirculation ballot of Version 0 standards. | December 27, 2004 –
January 7, 2005 |
| 4. 30-day posting before board adoption. | January 8, 2005 –
February 8, 2005 |
| 5. Board adopts Version 0 standards. | February 8, 2005 |
| 6. Effective date. | April 1, 2005 |

A. Introduction

- 1. Title:** Reliability Coordination – Facilities
- 2. Number:** IRO 002-0
- 3. Purpose:** Reliability Coordinators need information, tools and other capabilities to perform their responsibilities.
- 4. Applicability**
 - 4.1.** Reliability Coordinators.
- 5. Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** Each Reliability Coordinator shall have adequate communications facilities (voice and data links) to appropriate entities within its Reliability Coordinator Area. These communications facilities shall be staffed and available to act in addressing a real-time emergency condition.
- R2.** Each Reliability Coordinator shall determine the data requirements to support its reliability coordination tasks and shall request such data from its Transmission Operators, Balancing Authorities, Transmission Owners, Generation Owners, Generation Operators, and Load-Serving Entities, or adjacent Reliability Coordinators.
- R3.** Each Reliability Coordinator – or its Transmission Operators and Balancing Authorities – shall provide, or arrange provisions for, data exchange to other Reliability Coordinators or Transmission Operators and Balancing Authorities via a secure network.
- R4.** Each Reliability Coordinator shall have multi-directional communications capabilities with its Transmission Operators and Balancing Authorities, and with neighboring Reliability Coordinators, for both voice and data exchange as required to meet reliability needs of the Interconnection.
- R5.** Each Reliability Coordinator shall have detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its surrounding Reliability Coordinator Areas to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations are identified. Each Reliability Coordinator shall have monitoring systems that provide information that can be easily understood and interpreted by the Reliability Coordinator’s operating personnel, giving particular emphasis to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure.
- R6.** Each Reliability Coordinator shall monitor Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. Each Reliability Coordinator shall monitor 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.
- R7.** Each 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.
- R8.** Each Reliability Coordinator shall continuously monitor its Reliability Coordinator Area. Each Reliability Coordinator shall have provisions for backup facilities that shall be exercised if the main monitoring system is unavailable. Each Reliability Coordinator shall ensure SOL and IROL monitoring and derivations continue if the main monitoring system is unavailable.

R9. Each Reliability Coordinator shall control its Reliability Coordinator analysis tools, including approvals for planned maintenance. Each Reliability Coordinator shall have procedures in place to mitigate the effects of analysis tool outages.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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Anticipated Actions

Anticipated Date

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February 8, 2005 |
| 5. Board adopts Version 0 standards. | February 8, 2005 |
| 6. Effective date. | April 1, 2005 |

A. Introduction

- 1. **Title:** Reliability Coordination – Wide-Area View
- 2. **Number:** IRO-003-0
- 3. **Purpose:** The Reliability Coordinator must have a wide area view of its own Reliability Coordinator Area and that of neighboring Reliability Coordinators.
- 4. **Applicability**
 - 4.1. Reliability Coordinators.
- 5. **Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** Each Reliability Coordinator shall monitor all Bulk Electric System facilities, which may include sub-transmission information, 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 System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area.
- R2.** When a Reliability Coordinator is aware of an operational concern, such as declining voltages, excessive reactive flows, or an IROL violation, in a neighboring Reliability Coordinator Area, it shall contact the Reliability Coordinator in whose area the operational concern was observed. The two Reliability Coordinators shall coordinate any actions, including emergency assistance, required to mitigate the operational concern.
- R3.** Each Reliability Coordinator shall know the current status of all critical facilities whose failure, degradation or disconnection could result in an SOL or IROL violation. Reliability Coordinators shall also know the status of any facilities that may be required to assist area restoration objectives.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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Standard Development Roadmap

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Development Steps Completed:

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February 8, 2005 |
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| 6. Effective date. | April 1, 2005 |

A. Introduction

1. **Title:** Reliability Coordination – Staffing

2. **Number:** PER-004-0

3. **Purpose:**

Reliability Coordinators must have sufficient, competent staff to perform the Reliability Coordinator functions.

4. **Applicability**

4.1. Reliability Coordinators.

5. **Proposed Effective Date:** April 1, 2005

B. Requirements

R1. Each Reliability Coordinator shall be staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week.

R2. All Reliability Coordinator operating personnel shall each complete a minimum of five days per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel.

R3. Reliability Coordinator operating personnel shall have a comprehensive understanding of the Reliability Coordinator Area and interactions with neighboring Reliability Coordinator Areas.

R4. Reliability Coordinator operating personnel shall have an extensive understanding of the Balancing Authorities, Transmission Operators, and Generation Operators within the Reliability Coordinator Area, including the operating staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities, and operational restrictions.

R5. Reliability Coordinator operating personnel shall place particular attention on SOLs and IROLs and inter-tie facility limits. The Reliability Coordinator shall ensure protocols are in place to allow Reliability Coordinator operating personnel to have the best available information at all times.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
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Standard Development Roadmap

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February 8, 2005 |
| 5. Board adopts Version 0 standards. | February 8, 2005 |
| 6. Effective date. | April 1, 2005 |

A. Introduction

1. **Title:** **Reliability Coordination – Operations Planning**
2. **Number:** IRO-004-0
3. **Purpose:** Each Reliability Coordinator must conduct next-day reliability analyses for its Reliability Coordinator Area to ensure the Bulk Electric System can be operated reliably in anticipated normal and Contingency conditions. System studies must be conducted to highlight potential interface and other operating limits, including overloaded transmission lines and transformers, voltage and stability limits, etc. Plans must be developed to alleviate System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) violations.
4. **Applicability**
 - 4.1. Reliability Coordinators.
 - 4.2. Balancing Authorities.
 - 4.3. Transmission Operators.
 - 4.4. Transmission Service Providers.
 - 4.5. Transmission Owners.
 - 4.6. Generator Owners.
 - 4.7. Generator Operators.
 - 4.8. Load-Serving Entities.
5. **Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** Each 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. 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.
- R2.** Each 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.
- R3.** Each Reliability Coordinator shall, in conjunction with its Transmission Operators and Balancing Authorities, develop action plans that may be required, including reconfiguration of the transmission system, re-dispatching of generation, reduction or curtailment of Interchange Transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs.
- R4.** Each Transmission Operator, Balancing Authority, Transmission Owner, Generator Owner, Generator Operator, and Load-Serving Entity 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.
- R5.** Each Reliability Coordinator shall share the results of its system studies, when conditions warrant or upon request, with other Reliability Coordinators and with Transmission Operators,

Balancing Authorities, and Transmission Service Providers within its Reliability Coordinator Area. The Reliability Coordinator shall make study results 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.

- R6.** When conditions warrant, the Reliability Coordinator shall initiate a conference call or other appropriate communications to address the results of its reliability analyses.
- R7.** If the results of these studies indicate potential SOL or IROL violations, the Reliability Coordinator shall issue the appropriate alerts via the Reliability Coordinator Information System (RCIS) and direct its Transmission Operators, Balancing Authorities and Transmission Service Providers to take any necessary action the Reliability Coordinator deems appropriate to address the potential SOL or IROL violation.
- R8.** Each Transmission Operator, Balancing Authority, and Transmission Service Provider shall comply with the directives of its Reliability Coordinator based on the next day assessments in the same manner in which it would comply during real time operating events.

C. Measures

- M1.** Evidence that the Reliability Coordinator conducted next-day contingency analyses for its Reliability Coordinator Area to ensure that the Bulk Electric System could be operated reliably in anticipated normal and Contingency conditions.

D. Compliance

1. Compliance Monitoring Process

Entities will be selected for an on-site audit at least every three years. For a selected 30-day period in the previous three calendar months prior to the on site audit, Reliability Coordinators will be asked to provide documentation showing that next-day reliability analyses were conducted each day to ensure the bulk power system could be operated in anticipated normal and Contingency conditions; and that they identified potential interface and other operating limits including overloaded transmission lines and transformers, voltage and stability limits, etc.

1.1. Compliance Monitoring Responsibility

Self-Certification: Each Reliability Coordinator must annually self-certify compliance to its Regional Reliability Organization with the completion of the studies and action plans in Requirements R1, R2 and R3.

Exception Reporting: Reliability Coordinators will prepare a monthly report to the Regional Reliability Organization for each month that system studies were not conducted, indicating the dates that studies were not done and the reason why.

1.2. Compliance Monitoring Period and Reset Timeframe

One year without a violation from the time of the violation.

1.3. Data Retention

Documentation shall be available for 3 months to provide verification that system studies were performed as required.

1.4. Additional Compliance Information

None identified.

2. Levels of Non-Compliance

- 2.1. Level 1:** System studies were not conducted for one day in a calendar month and/or the action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other IROL violations.
- 2.2. Level 2:** System studies were not conducted for 2–3 days in a calendar month and/or the action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other IROL violations.
- 2.3. Level 3:** System studies were not conducted for 4–5 days in a calendar month and/or the action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other IROL violations.
- 2.4. Level 4:** System studies were not conducted for more than 5 days in a calendar month and/or the action plans were not developed to maintain transmission loading within acceptable limits for potential interface and other IROL violations.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAC approves Version 0 SAR for posting (April 14, 2004).
2. SAC approves *Plan for Accelerating Adoption of NERC Reliability Standards* (April 19, 2004).
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Description of Current Draft:

Draft 3 is to be posted for a 30-day posting prior to balloting the Version 0 standards. This draft includes revisions based on industry comments received during the posting of Draft 2. Changes from Draft 2 are highlighted in the redline copy of Draft 3.

Future Development Plan:

Anticipated Actions

Anticipated Date

- | | |
|---|--|
| 1. Seek endorsement of NERC technical committees. | November 9–11, 2004 |
| 2. First ballot of Version 0 standards. | December 1–10, 2004 |
| 3. Recirculation ballot of Version 0 standards. | December 27, 2004 –
January 7, 2005 |
| 4. 30-day posting before board adoption. | January 8, 2005 –
February 8, 2005 |
| 5. Board adopts Version 0 standards. | February 8, 2005 |
| 6. Effective date. | April 1, 2005 |

A. Introduction

- 1. Title:** Reliability Coordination – Current Day Operations
- 2. Number:** IRO-005-0
- 3. Purpose:** The Reliability Coordinator must be continuously aware of conditions within its Reliability Coordinator Area and include this information in its reliability assessments. The Reliability Coordinator must monitor Bulk Electric System parameters that may have significant impacts upon the Reliability Coordinator Area and neighboring Reliability Coordinator Areas.
- 4. Applicability**
 - 4.1.** Reliability Coordinators.
 - 4.2.** Balancing Authorities.
 - 4.3.** Transmission Operators.
 - 4.4.** Transmission Service Providers.
- 5. Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** Each Reliability Coordinator shall monitor its Reliability Coordinator Area parameters, including but not limited to the following:
 - R1.1.** 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.
 - R1.2.** Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
 - R1.3.** Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope.
 - R1.4.** System real and reactive reserves (actual versus required).
 - R1.5.** Capacity and energy adequacy conditions.
 - R1.6.** Current ACE for all its Balancing Authorities.
 - R1.7.** Current local or Transmission Loading Relief procedures in effect.
 - R1.8.** Planned generation dispatches.
 - R1.9.** Planned transmission or generation outages.
 - R1.10.** Contingency events.
- R2.** Each 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.
- R3.** As portions of the transmission system approach or exceed SOLs or IROLs, the Reliability Coordinator shall work with its Transmission Operators and Balancing Authorities to evaluate and assess any additional Interchange Schedules that would violate those limits. If a 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. The Reliability Coordinator shall ensure all resources, including load shedding, are available to address a potential or actual IROL violation.

- R4.** Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.
- R5.** Each Reliability Coordinator shall identify the cause of any potential or actual SOL or IROL violations. The Reliability Coordinator shall initiate the control action or emergency procedure to relieve the potential or actual IROL violation without delay, and no longer than 30 minutes. The Reliability Coordinator shall be able to utilize all resources, including load shedding, to address an IROL violation.
- R6.** Each Reliability Coordinator shall ensure its Transmission Operators and Balancing Authorities are aware of Geo-Magnetic Disturbance (GMD) forecast information and assist as needed in the development of any required response plans.
- R7.** The Reliability Coordinator shall participate in NERC hotline discussions, assist in the assessment of reliability of the overall interconnected system, and coordinate actions in anticipated or actual emergency situations. The Reliability Coordinator shall disseminate such information within its Reliability Coordinator Area, as required.
- R8.** Each Reliability Coordinator shall monitor system frequency and its Balancing Authorities' performance and direct any necessary rebalancing to return to CPS and DCS compliance. The Transmission Operators and Balancing Authorities shall utilize all resources, including firm load shedding, as directed by its Reliability Coordinator to relieve the emergent condition.
- R9.** The Reliability Coordinator shall coordinate with other Reliability Coordinators and Transmission Operators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. The Reliability Coordinator shall coordinate pending generation and transmission maintenance outages with other Reliability Coordinators and Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes.
- R10.** As necessary, the Reliability Coordinator shall assist the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities.
- R11.** The Reliability Coordinator shall identify sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and shall discuss corrective actions with the appropriate Balancing Authority. If a Frequency Error, Time Error, or inadvertent problem occurs outside of the Reliability Coordinator Area, the Reliability Coordinator shall initiate a NERC hotline call to discuss the Frequency Error, Time Error, or Inadvertent Interchange with other Reliability Coordinators. The Reliability Coordinator shall direct its Balancing Authority to comply with CPS and DCS.
- R12.** Whenever a Special Protection System that may have an inter-Balancing Authority, inter-Transmission Operator, 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 of that Special Protection System on inter-area flows. The Transmission Operator shall immediately inform the Reliability Coordinator of the status of the Special Protection System including any degradation or potential failure to operate as expected.

- R13.** Each Reliability Coordinator shall ensure that all Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities 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. In instances where there is a difference in derived limits, the Reliability Coordinator and its Transmission Operators, Balancing Authorities, Generator Operators, Transmission Service Providers, Load-Serving Entities, and Purchasing-Selling Entities shall always operate the Bulk Electric System to the most limiting parameter.
- R14.** Each Reliability Coordinator shall make known to Transmission Service Providers within its Reliability Coordinator Area, SOLs or IROLs within its wide-area view. The Transmission Service Providers shall respect these SOLs or IROLs in accordance with filed tariffs and regional Total Transfer Calculation and Available Transfer Calculation processes.
- R15.** Each 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 impacted Transmission Operators and Balancing Authorities in its Reliability Coordinator Area, and all impacted Reliability Coordinators within the Interconnection via the Reliability Coordinator Information System (RCIS) without delay. The receiving Reliability Coordinator shall disseminate this information to its impacted Transmission Operators and Balancing Authorities. The Reliability Coordinator shall notify all impacted Transmission Operators, Balancing Authorities, and Reliability Coordinators when the transmission problem has been mitigated.
- R16.** Each Reliability Coordinator shall confirm reliability assessment results and determine the effects within its own and adjacent Reliability Coordinator Areas. The Reliability Coordinator shall discuss options to mitigate potential or actual SOL or IROL violations and take actions as necessary to always act in the best interests of the Interconnection at all times.
- R17.** When an IROL or SOL is exceeded, the Reliability Coordinator shall evaluate the local and wide-area impacts, both real-time and post-contingency, and determine if the actions being taken are appropriate and sufficient to return the system to within IROL in thirty minutes. If the actions being taken are not appropriate or sufficient, the Reliability Coordinator shall direct the Transmission Operator, Balancing Authority, Generator Operator, or Load-Serving Entity to return the system to within IROL or SOL.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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Standard Development Roadmap

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Anticipated Date

November 9–11, 2004
December 1–10, 2004
December 27, 2004 –
January 7, 2005
January 8, 2005 –
February 8, 2005
February 8, 2005
April 1, 2005

A. Introduction

1. **Title:** **Reliability Coordination – Transmission Loading Relief**
2. **Number:** IRO-006-0
3. **Purpose:** Regardless of the process it uses, the Reliability Coordinator must direct its Balancing Authorities and Transmission Operators to return the transmission system to within its Interconnection Reliability Operating Limits as soon as possible, but no longer than 30 minutes. The Reliability Coordinator needs to direct Balancing Authorities and Transmission Operators to execute actions such as reconfiguration, redispatch, or load shedding until relief requested by the TLR process is achieved.
4. **Applicability**
 - 4.1. Reliability Coordinators.
 - 4.2. Transmission Operators.
 - 4.3. Balancing Authorities.
5. **Proposed Effective Date:** April 1, 2005

B. Requirements

- R1. A Reliability Coordinator shall take appropriate actions in accordance with established policies, procedures, authority, and expectations to relieve transmission loading.
- R2. A Reliability Coordinator experiencing a potential or actual SOL or IROL violation 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.
 - R2.1. The Interconnection-wide Transmission Loading Relief (TLR) procedure for use in the Eastern Interconnection is provided in Attachment 1-IRO-006-0.
 - R2.2. The equivalent Interconnection-wide transmission loading relief procedure for use in the Western Interconnection is the “WSCC Unscheduled Flow Mitigation Plan,” provided at:
http://www.wecc.biz/documents/publications/UFAS_mitigation_plan_rev_2001-clean_8-8-03.pdf.
 - R2.3. The Interconnection-wide transmission loading relief procedure for use in ERCOT is provided as Section 7 of the ERCOT Protocols, posted at:
<http://www.ercot.com/tac/retailisoadhoccommittee/protocols/keydocs/draftercotprotocols.htm>.
- R3. The Reliability Coordinator may use local transmission loading relief or congestion management procedures, provided the Transmission Operator experiencing the potential or actual SOL or IROL violation is a party to those procedures.
- R4. A Reliability Coordinator may implement a local transmission loading relief or congestion management procedure simultaneously with an Interconnection-wide procedure. However, the Reliability Coordinator shall follow the curtailments as directed by the Interconnection-wide procedure. A Reliability Coordinator desiring to use a local procedure as a substitute for curtailments as directed by the Interconnection-wide procedure shall have such use approved by the NERC Operating Committee.
- R5. When implemented, all Reliability Coordinators shall comply with the provisions of the Interconnection-wide procedure including, for example, action by Reliability Coordinators in

other Interconnections to curtail an Interchange Transaction that crosses an Interconnection boundary.

- R6.** During the implementation of relief procedures, and up to the point that emergency action is necessary, Reliability Coordinators and Balancing Authorities shall comply with interchange scheduling standards INT-001 through INT-004.

C. Measures

- M1.** If required, an investigation will be conducted to determine whether appropriate actions were taken in accordance with established policies, procedures, authority, and expectations to relieve transmission loading, including notifying appropriate Reliability Coordinators and operating entities to curtail Interchange Transactions.

D. Compliance

1. Compliance Monitoring Process

The Regional Reliability Organization or NERC may initiate an investigation if there is a complaint that an entity has not implemented relief procedures in accordance with these requirements.

1.1. Compliance Monitoring Responsibility

Not specified.

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance Monitoring Period: One calendar year.

Reset Period: One month without a violation.

1.3. Data Retention

One calendar year.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

2.1. Level 1: N/A.

2.2. Level 2: N/A.

2.3. Level 3: N/A.

2.4. Level 4: The Reliability Coordinator did not implement loading relief procedures in accordance with the standard.

E. Regional Differences

PJM/MISO Enhanced Congestion Management (Curtailment/Reload/Reallocation) Waiver approved March 25, 2004.

Version History

Version	Date	Action	Change Tracking
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Attachment 1-IRO-006-0

Transmission Loading Relief Procedure — Eastern Interconnection

Purpose

This standard defines procedures for curtailment and reloading of Interchange Transactions to relieve overloads on transmission facilities modeled in the Interchange Distribution Calculator. This process is defined in the requirements below, and is depicted in Appendix A. Examples of curtailment calculations using these procedures are contained in Appendix B.

Applicability

This standard only applies to the Eastern Interconnection.

1. Transmission Loading Relief (TLR) Procedure

- 1.1. Initiation only by Reliability Coordinator.** A Reliability Coordinator shall be the only entity authorized to initiate the TLR Procedure and shall do so at 1) the Reliability Coordinator's own request, or 2) upon the request of a Transmission Operator.
- 1.2. Mitigating transmission constraints.** A Reliability Coordinator may utilize the TLR Procedure to mitigate potential or actual System Operating Limit (SOL) violations or Interconnection Reliability Operating Limit (IROL) violations on any transmission facility modeled in the IDC.
 - 1.2.1. Requesting relief on tie facilities.** Any Transmission Operator who operates the tie facility shall be allowed to request relief from its Reliability Coordinator.
 - 1.2.1.1. Interchange Transaction priority on tie facilities.** The priority of the Interchange Transaction(s) to be curtailed shall be determined by the Transmission Service reserved on the Transmission Service Provider's system who requested the relief.
- 1.3. Order of TLR Levels and taking emergency action.** The Reliability Coordinator shall not be required to follow the TLR Levels in their numerical order (Section 2, "TLR Levels"). Furthermore, if a Reliability Coordinator deems that a transmission loading condition could jeopardize Bulk Electric System reliability, the Reliability Coordinator shall have the authority to enter TLR Level 6 directly, and immediately direct the Balancing Authorities or Transmission Operators to take such actions as redispatching generation, or reconfiguring transmission, or reducing load to mitigate the critical condition until Interchange Transactions can be reduced utilizing the TLR Procedure or other methods to return the system to a secure state.
- 1.4. Notification of TLR Procedure implementation.** The Reliability Coordinator initiating the use of the TLR Procedure shall notify other Reliability Coordinators and Balancing Authorities and Transmission Operators, and must post the initiation and progress of the TLR event on the appropriate NERC web page(s).
 - 1.4.1. Notifying other Reliability Coordinators.** The Reliability Coordinator initiating the TLR Procedure shall inform all other Reliability Coordinators via the Reliability Coordinator Information System (RCIS) that the TLR Procedure has been implemented.
 - 1.4.1.1. Actions expected.** The Reliability Coordinator initiating the TLR Procedure shall indicate the actions expected to be taken by other Reliability Coordinators.

- 1.4.2. Notifying Transmission Operators and Balancing Authorities.** The Reliability Coordinator shall notify Transmission Operators and Balancing Authorities in its Reliability Area when entering and leaving any TLR level.
- 1.4.3. Notifying Balancing Authorities.** The Reliability Coordinator for the sink Balancing Authority shall be responsible for directing the Sink Balancing Authority to curtail the Interchange Transactions as specified by the Reliability Coordinator implementing the TLR Procedure.

 - 1.4.3.1. Notification order.** Within a Transmission Service Priority level, the Sink Balancing Authorities whose Interchange Transactions have the largest impact on the Constrained Facilities shall be notified first if practicable.
- 1.4.4. Updates.** At least once each hour, or when conditions change, the Reliability Coordinator implementing the TLR Procedure shall update all other Reliability Coordinators (via the RCIS). Transmission Operators and Balancing Authorities who have had Interchange Transactions impacted by the TLR will be updated by their Reliability Coordinator.
- 1.5. Obligations.** All Reliability Coordinators shall comply with the request of the Reliability Coordinator who initiated the TLR Procedure, unless the initiating Reliability Coordinator agrees otherwise.

 - 1.5.1. Use of TLR Procedure with “local” procedures.** A Reliability Coordinator shall be allowed to implement a local transmission loading relief or congestion management procedure simultaneously with an Interconnection-wide procedure. However, the Reliability Coordinator shall be 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 Committee.
- 1.6. Consideration of Interchange Transactions.** The administration of the TLR Procedure shall be guided by information obtained from the IDC.

 - 1.6.1. Interchange Transactions not in the IDC.** Reliability Coordinators shall also treat known Interchange Transactions that may not appear in the IDC in accordance with the procedures in this document.
 - 1.6.2. Transmission elements not in IDC.** When a Reliability Coordinator is faced with an overload on a transmission element that is not modeled in the IDC, the Reliability Coordinator shall use the best information available to curtail Interchange Transactions in order to operate the system in a reliable manner. The Reliability Coordinator shall use its best efforts to ensure that Interchange Transactions with a Transfer Distribution Factor of less than the Curtailment Threshold on the transmission element not modeled in the IDC are not curtailed.
 - 1.6.3. Questionable IDC results.** Any Reliability Coordinator (or Transmission Operator through its Reliability Coordinator) who believes the curtailment list from the IDC for a particular TLR event is incorrect shall use its best efforts to communicate those adjustments necessary to bring the curtailment list into conformance with the principles of this Procedure to the initiating Reliability Coordinator. Causes of questionable IDC results may include:

- Missing Interchange Transactions that are known to contribute to the Constraint.
- Significant change in transmission system topology.
- TDF matrix error.

Impacts of questionable IDC results may include:

- Curtailment that would have no effect on, or aggravate the constraint.
- Curtailment that would initiate a constraint elsewhere.

If other Reliability Coordinators are involved in the TLR event, all impacted Reliability Coordinators shall be in agreement before any adjustments to the Curtailment list are made.

1.6.4. Curtailment that would cause a constraint elsewhere. A Reliability Coordinator shall be allowed to exempt an Interchange Transaction from Curtailment if that Reliability Coordinator is aware that the Interchange Transaction Curtailment directed by the IDC would cause a constraint to occur elsewhere. This exemption shall only be allowed after the Reliability Coordinator has consulted with the Reliability Coordinator who initiated the Curtailment.

1.6.5. Redispatch options. The Reliability Coordinator shall ensure that Interchange Transactions that are linked to redispatch options are protected from Curtailment in accordance with the redispatch provisions.

1.6.6. Reallocation. The Reliability Coordinator shall consider for Reallocation any Transactions of higher priority that meet the approved tag submission deadline during a TLR Level 3A. The Reliability Coordinator shall consider for Reallocation any Transaction using Firm Transmission Service that has met the approved tag submission deadline during a TLR Level 5A.

1.7 IDC updates. Any Interchange Transaction adjustments or curtailments that result from using this Procedure must be entered into the IDC.

1.8 Logging. The Reliability Coordinator shall complete the NERC Transmission Loading Relief Procedure Log whenever it invokes TLR Level 2 or above, and send a copy of the log via email to NERC within two business days of the TLR event for posting on the NERC website.

1.9 TLR Event Review. The Reliability Coordinator shall report the TLR event to the NERC Market Committee and Operating Reliability Subcommittee in accordance with TLR review processes established by NERC as required.

1.9.1. Providing information. Transmission Operators and Balancing Authorities within the Reliability Coordinator's Area, and all other Reliability Coordinators, including Transmission Operators and Balancing Authorities within their respective Reliability Areas, shall provide information, as requested by the initiating Reliability Coordinator, in accordance with TLR review processes established by NERC.

1.9.2. Market Committee reviews. The Market Committee may conduct reviews of certain TLR events based on the size and number of Interchange Transactions that are affected, the frequency that the TLR Procedure is called for a particular Constrained Facility, or other factors.

- 1.9.3. Operating Reliability Subcommittee reviews.** The Operating Reliability Subcommittee shall conduct reviews to ensure proper implementation and for “lessons learned.”

2. Transmission Loading Relief (TLR) Levels

Introduction

This section describes the various levels of the TLR Procedure. The description of each level begins with the circumstances that define the TLR Level, followed by the procedures to be followed.

The decision that a Reliability Coordinator makes in selecting a particular TLR Level often depends on the transmission loading condition and whether the Interchange Transaction is using Non-firm Point-to-Point Transmission Service or Firm Point-to-Point Transmission Service. There are further considerations that depend on whether the Constrained Facility is on or off the Contract Path. It is important to note that an Interchange Transaction using Firm Point-to-Point Transmission Service on all Contract Path links is considered a “firm” Interchange Transaction even if the Constrained Facility is off the Contract Path.

2.1. TLR Level 1 — Notify Reliability Coordinators of potential SOL or IROL Violations

2.1.1. The Reliability Coordinator shall use the following circumstances to establish the need for TLR Level 1:

- The transmission system is secure.
- The Reliability Coordinator foresees a transmission or generation contingency or other operating problem within its Reliability Area that could cause one or more transmission facilities to approach or exceed their SOL or IROL.

2.1.2. Notification procedures. The Reliability Coordinator shall notify all Reliability Coordinators via the Reliability Coordinator Information System (RCIS) as soon as the condition is foreseen. All affected Reliability Coordinators shall check to ensure that Interchange Transactions are posted in the IDC.

2.2. TLR Level 2 — Hold transfers at present level to prevent SOL or IROL Violations

2.2.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 2:

- The transmission system is secure.
- One or more transmission facilities are expected to approach, or are approaching, or are at their SOL or IROL.

2.2.2. Holding procedures. The Reliability Coordinator shall be allowed to hold the implementation of any additional Interchange Transactions that are at or above the Curtailment Threshold. However, the Reliability Coordinator should allow additional Interchange Transactions that flow across the Constrained Facility if their flow reduces the loading on the Constrained Facility or has a Transfer Distribution Factor less than the Curtailment Threshold. All Interchange Transactions using Firm Point-to-Point Transmission Service shall be allowed to start.

2.2.3. TLR Level 2 is a transient state, which requires a quick decision to proceed to higher TLR Levels (3 and above) to allow Interchange Transactions to be implemented according to their transmission reservation priority. The time for

being in TLR Level 2 should be no more than 30 minutes, with the understanding that there may be circumstances where this time may be exceeded. If the time in TLR Level 2 exceeds 30 minutes, the Reliability Coordinator shall document this action on the TLR Log.

2.3. TLR Level 3a — Reallocation of Transmission Service by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Transmission Service

2.3.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 3a:

- The transmission system is secure.
- One or more transmission facilities are expected to approach, or are approaching, or are at their SOL or IROL.
- Transactions using Non-firm Point-to-Point Transmission Service are flowing that are at or above the Curtailment Threshold on those facilities.
- The Transmission Provider has previously approved a higher priority Point-to-Point Transmission Service reservation over which a Transmission Customer wishes to begin an Interchange Transaction.

2.3.2. Reallocation procedures to allow Interchange Transactions using higher priority Point-to-Point Transmission Service to start. The Reliability Coordinator with the constraint shall give preference to those Interchange Transactions using Firm Point-to-Point Transmission Service, followed by those using higher priority Non-firm Point-to-Point Transmission Service as specified in Section 3. “Interchange Transaction Curtailment Order.” Interchange Transactions that have been held or curtailed as prescribed in this Section shall be reallocated (reloaded) according to their Transmission Service priorities when operating conditions permit as specified in Section 6. “Interchange Transaction Reallocation During TLR Level 3a and 5a.”

2.3.2.1. The Reliability Coordinator shall displace Interchange Transactions with lower priority Transmission Service using Interchange Transactions having higher priority Non-firm or Firm Transmission Service.

2.3.2.2. The Reliability Coordinator shall not curtail Interchange Transactions using Non-firm Transmission Service to allow the start or increase of another Interchange Transaction having the same priority Non-firm Transmission Service.

2.3.2.3. If there are insufficient Interchange Transactions using Non-firm Point-to-Point Transmission Service that can be curtailed to allow for Interchange Transactions using Firm Point-to-Point Transmission Service to begin, the Reliability Coordinator shall proceed to TLR Level 5a.

2.3.2.4. The Reliability Coordinator shall reload curtailed Interchange Transactions prior to allowing the start of new or increased Interchange Transactions.

2.3.2.4.1. Interchange Transactions whose tags were submitted prior to the TLR Level 2 or Level 3a being called, but were subsequently held from starting, are considered to have been

curtailed and thus would be reloaded the same time as the curtailed Interchange Transactions.

2.3.2.5. The Reliability Coordinator shall fill available transmission capability by reloading or starting eligible Transactions on a pro-rata basis.

2.3.2.6. The Reliability Coordinator shall consider transactions whose tags meet the approved tag submission deadline for Reallocation for the upcoming hour. Tags submitted after this deadline shall be considered for Reallocation the following hour.

2.4. TLR Level 3b — Curtail Interchange Transactions using Non-Firm Transmission Service Arrangements to mitigate a SOL or IROL Violation

2.4.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 3b:

- One or more transmission facilities are operating above their SOL or IROL, or
- Such operation is imminent and it is expected that facilities will exceed their reliability limit unless corrective action is taken, or
- One or more Transmission Facilities will exceed their SOL or IROL upon the removal from service of a generating unit or another transmission facility.
- Transactions using Non-firm Point-to-Point Transmission Service are flowing that are at or above the Curtailment Threshold on those facilities.

2.4.2. Holding new Interchange Transactions. The Reliability Coordinator shall hold all new Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold during the period of the SOL or IROL Violation. The Reliability Coordinator shall allow Interchange Transactions using Firm Point-to-Point Transmission Service to start if they are submitted to the IDC within specific time limits as explained in Section 7. “Interchange Transaction Curtailments during TLR Level 3b.”

2.4.3. Curtailment procedures to mitigate an SOL or IROL. The Reliability Coordinator shall curtail Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold as specified in Section 3, “Interchange Transaction Curtailment Order.”

2.5. TLR Level 4 — Reconfigure Transmission

2.5.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 4:

- One or more Transmission Facilities are above their SOL or IROL, or
- Such operation is imminent and it is expected that facilities will exceed their reliability limit unless corrective action is taken.

2.5.2. Holding new Interchange Transactions. The Reliability Coordinator shall hold all new Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold during the period of the SOL or IROL Violation. The Reliability Coordinator shall allow Interchange Transactions using Firm Point-to-Point Transmission Service to start if they are submitted to the IDC by 25 minutes past the hour or the time at which the TLR

Level 4 is called, whichever is later. See Appendix E, Section E2 – Timing Requirements.

2.5.3. Reconfiguration procedures. Following the curtailment of all Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold in Level 3b that impact the Constrained Facilities, if a SOL or IROL violation is imminent or occurring, the Reliability Coordinator(s) shall request that the affected Transmission Operators reconfigure transmission on their system, or arrange for reconfiguration on other transmission systems, to mitigate the constraint. Specific details are explained in Section 4, “Principles for Mitigating Constraints On and Off the Contract Path”.

2.6. TLR Level 5a — Reallocation of Transmission Service by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro rata basis to allow additional Interchange Transactions using Firm Point-to-Point Transmission Service

2.6.1. The Reliability Coordinator shall use the following circumstances to establish the need for entering TLR Level 5a:

- The transmission system is secure.
- One or more transmission facilities are at their SOL or IROL.
- All Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold have been curtailed.
- The Transmission Provider has been requested to begin an Interchange Transaction using previously arranged Firm Transmission Service that would result in a SOL or IROL violation.
- No further transmission reconfiguration is possible or effective.

2.6.2. Reallocation procedures to allow new Interchange Transactions using Firm Point-to-Point Transmission Service to start. The Reliability Coordinator shall use the following three-step process for Reallocation of Interchange Transactions using Firm Point-to-Point Transmission Service:

2.6.2.1. Step 1 — Identify available redispatch options. The Reliability Coordinator shall assist the Transmission Operator(s) in identifying those known redispatch options that are available to the Transmission Customer that will mitigate the loading on the Constrained Facilities. If such redispatch options are deemed insufficient to mitigate loading on the Constrained Facilities, the Reliability Coordinator shall proceed to implement these options while proceeding to Steps 2 and 3 below.

2.6.2.2. Step 2 — The Reliability Coordinator shall calculate the percent of the overload on the Constrained Facility caused by both Firm Point-to-Point Transmission Service (at or above the Curtailment Threshold) and the Transmission Provider’s Network Integration Transmission Service and Native Load, as required by the Transmission Provider’s filed tariff. This is described in Section 5, “Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service.”

2.6.2.3. Step 3 — Curtail Interchange Transactions using Firm Transmission Service. The Reliability Coordinator shall curtail or reallocate on a pro-

rata basis (based on the MW level of the MW total to all such Interchange Transactions), those Interchange Transactions as calculated in Section 7.2.2 over the Constrained Facilities. (See also Section 6, “Interchange Transaction Reallocation during TLR 3a and 5a.”) The Reliability Coordinator shall assist the Transmission Provider in curtailing Transmission Service to Network Integration Transmission Service customers and Native Load if such curtailments are required by the Transmission Provider’s tariff. Available redispatch options will continue to be implemented.

2.7. TLR Level 5b — Curtail Interchange Transactions using Firm Point-to-Point Transmission Service to mitigate an SOL or IROL violation

2.7.1. The Reliability Coordinator shall use following circumstances to establish the need for entering TLR Level 5b:

- One or more Transmission Facilities are operating above their SOL or IROL, or
- Such operation is imminent, or
- One or more Transmission Facilities will exceed their SOL or IROL upon the removal from service of a generating unit or another transmission facility.
- All Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold have been curtailed.
- No further transmission reconfiguration is possible or effective.

2.7.2. The Reliability Coordinator shall use the following three-step process for curtailment of Interchange Transactions using Firm Point-to-Point Transmission Service:

2.7.2.1. Step 1 — Identify available redispatch options. The Reliability Coordinator shall assist the Transmission Operator(s) in identifying those known redispatch options that are available to the Transmission Customer that will mitigate the loading on the Constrained Facilities. If such redispatch options are deemed insufficient to mitigate loading on the Constrained Facilities, the Reliability Coordinator shall proceed to implement these options while proceeding to Steps 2 and 3 below.

2.7.2.2. Step 2 — The Reliability Coordinator shall calculate the percent of the overload on the Constrained Facility caused by both Firm Point-to-Point Transmission Service (at or above the Curtailment Threshold) and the Transmission Provider’s Network Integration Transmission Service and Native Load, as required by the Transmission Provider’s filed tariff. This is described in Section 5, “Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service.”

2.7.2.3. Step 3 — Curtailment of Interchange Transactions using Firm Transmission Service. At this point, the Reliability Coordinator shall begin the process of curtailing Interchange Transactions as calculated in Section 2.7.2.2 over the Constrained Facilities using Firm Point-to-Point Transmission Service until the SOL or IROL violation has been mitigated. The Reliability Coordinator shall assist the Transmission Provider in curtailing Transmission Service to Network Integration Transmission Service customers and Native Load if such curtailments

are required by the Transmission Providers' tariff. Available redispatch options will continue to be implemented.

2.8. TLR Level 6 — Emergency Procedures

2.8.1. The Reliability Coordinator shall use following circumstances to establish the need for entering TLR Level 6:

- One or more Transmission Facilities are above their SOL or IROL.
- One or more Transmission Facilities will exceed their SOL or IROL upon the removal from service of a generating unit or another transmission facility.

2.8.2. Implementing emergency procedures. If the Reliability Coordinator deems that transmission loading is critical to Bulk Electric System reliability, the Reliability Coordinator shall immediately direct the Balancing Authorities and Transmission Operators in its Reliability Area to redispatch generation, or reconfigure transmission, or reduce load to mitigate the critical condition until Interchange Transactions can be reduced utilizing the TLR Procedures or other procedures to return the system to a secure state. All Balancing Authorities and Transmission Operators shall comply with all requests from their Reliability Coordinator.

2.9. TLR Level 0 — TLR concluded

2.9.1. Interchange Transaction restoration and notification procedures. The Reliability Coordinator initiating the TLR Procedure shall notify all Reliability Coordinators within the Interconnection via the RCIS when the SOL or IROL violations are mitigated and the system is in a reliable state, allowing Interchange Transactions to be reestablished at its discretion. Those with the highest transmission priorities shall be reestablished first if possible.

3. Interchange Transaction Curtailment Order for use in TLR Procedures

3.1. Priority of Interchange Transactions

3.1.1. Interchange Transaction curtailment priority shall be determined by the Transmission Service reserved over the constrained facility(ies) as follows:

Transmission Service Priorities

- Priority 0. Next-hour Market Service — NX*
- Priority 1. Service over secondary receipt and delivery points — NS
- Priority 2. Non-Firm Point-to-Point Hourly Service — NH
- Priority 3. Non-Firm Point-to-Point Daily Service — ND
- Priority 4. Non-Firm Point-to-Point Weekly Service — NW
- Priority 5. Non-Firm Point-to-Point Monthly Service — NM
- Priority 6. Network Integration Transmission Service from sources not designated as network resources — NN
- Priority 7. Firm Point-to-Point Transmission Service — F and Network Integration Transmission Service from Designated Resources — FN

3.1.2. The curtailment priority for Interchange Transactions that do not have a Transmission Service reservation over the constrained facility(ies) shall be defined by the lowest priority of the individual reserved transmission segments.

3.2. Curtailment of Interchange Transactions Using Non-firm Transmission Service

3.2.1. The Reliability Coordinator shall direct the curtailment of Interchange Transactions using Non-firm Transmission Service that are at or above the Curtailment Threshold for the following TLR Levels:

3.2.1.1. TLR Level 3a. Enable Interchange Transactions using a higher Transmission reservation priority to be implemented, or

3.2.1.2. TLR Level 3b. Mitigate an SOL or IROL violation.

3.3. Curtailment of Interchange Transactions Using Firm Transmission Service

3.3.1. The Reliability Coordinator shall direct the curtailment of Interchange Transactions using Firm Transmission Service that are at or above the Curtailment Threshold for the following TLR Levels:

3.3.1.1. TLR Level 5a. Enable additional Interchange Transactions using Firm Point-to-Point Transmission Service to be implemented after all Interchange Transactions using Non-firm Point-to-Point Service have been curtailed, or

3.3.1.2. TLR Level 5b. Mitigate a SOL or IROL violation that remains after all Interchange Transactions using Non-firm Transmission Service has been curtailed under TLR Level 3b, and following attempts to reconfigure transmission under TLR Level 4.

4. Mitigating Constraints On and Off the Contract Path during TLR

Introduction

Reserving Transmission Service for an Interchange Transaction along a Contract Path may not reflect the actual distribution of the power flows over the transmission network from generation source to load sink. Interchange Transactions arranged over a Contract Path may, therefore, overload transmission elements on other electrically parallel paths.

The curtailment priority of an Interchange Transaction depends on whether the Constrained Facility is on or off the Contract Path as detailed below.

4.1. Constraints ON the Contract Path

- 4.1.1.** The Reliability Coordinator initiating TLR shall consider the entire Interchange Transaction non-firm if the transmission link (i.e., a segment on the Contract Path) on the Constrained Facility is Non-firm Point-to-Point Transmission Service, even if other links in the Contract Path are firm. When the Constrained Facility is on the Contract Path, the Interchange Transaction takes on the Transmission Service Priority of the Transmission Service link with the Constrained Facility regardless of the Transmission Service Priority on the other links along the Contract Path.

Discussion. The Transmission Operator simply has to call its Reliability Coordinator, request the TLR Procedure be initiated, and allow the curtailments of all Interchange Transactions that are at or above the Curtailment Threshold to progress until the relief is realized. Firm Point-to-Point Transmission Service links elsewhere in the Contract Path do not obligate Transmission Providers providing Non-firm Point-to-Point Transmission Service to treat the transaction as firm. For curtailment purposes, the Interchange Transaction's priority will be the priority of the Transmission Service link with the Constrained Facility. (See Requirement 4.1.2 below.)

- 4.1.2.** The Reliability Coordinator initiating TLR shall consider the entire Interchange Transaction firm if the transmission link on the Constrained Facility is Firm Point-to-Point Transmission Service, even if other links in the Contract Path are non-firm.

Discussion. The curtailment priority of an Interchange Transaction on a Contract Path link is not affected by the Transmission Service Priorities arranged with other links on the Contract Path. If the Constrained Facility is on a Firm Point-to-Point Transmission Service Contract Path link, then the curtailment priority of the Interchange Transaction is considered firm regardless of the Transmission Service arrangements elsewhere on the Contract Path. If the Transmission Provider provides its services under the FERC pro forma tariff, it may also be obligated to offer its Transmission Customer alternate receipt and delivery points, thus allowing the customer to curtail its Transmission Service over the Constrained Facilities.

4.2. Constraints OFF the Contract Path

- 4.2.1.** The Reliability Coordinator initiating TLR shall consider the entire Interchange Transaction non-firm if none of the transmission links on the Contract Path are on the Constrained Facility and if any of the transmission links on the Contract Path are Non-firm Point-to-Point Transmission Service; the Interchange

Transaction shall take on the lowest Transmission Service Priority of all Transmission Service links along the Contract Path.

Discussion. An Interchange Transaction arranged over a Contract Path where one or more individual links consist of Non-firm Point-to-Point Transmission Service is considered to be a non-firm Interchange Transaction for Constrained Facilities off the Contract Path. Sufficient Interchange Transactions that are at or above the Curtailment Threshold will be curtailed before any Interchange Transactions using Firm Point-to-Point Transmission Service are curtailed. The priority level for curtailment purposes will be the lowest level of Transmission Service arranged for on the Contract Path.

- 4.2.2.** The Reliability Coordinator initiating TLR shall consider the entire Interchange Transaction firm if all of the transmission links on the Contract Path are Firm Point-to-Point Transmission Service, even if none of the transmission links are on the Constrained Facility and shall not be curtailed to relieve a Constraint off the Contract Path until all non-firm Interchange Transactions that are at or above the Curtailment Threshold have been curtailed.

Discussion. If the entire Contract Path is Firm Point-to-Point Transmission Service, then the TLR procedure will treat the Interchange Transaction as firm, even for Constraints off the Contract Path, and will not curtail that Interchange Transaction until all non-firm Interchange Transactions that are at or above the Curtailment Threshold have been curtailed. However, Transmission Providers off the Contract Path are not obligated to reconfigure their transmission system or provide other congestion management procedures unless special arrangements are in place. Because the Interchange Transaction is considered firm everywhere, the Reliability Coordinator may attempt to arrange for Transmission Operators to reconfigure transmission or provide other congestion management options or Balancing Authorities to redispatch, even if they are off the Contract Path, to try to avoid curtailing the Interchange Transaction that is using the Firm Point-to-Point Transmission Service.

5. Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service during TLR

Introduction

The provision of Point-to-Point Transmission Service, Network Integration Transmission Service and service to Native Load results in parallel flows on the transmission network of other Transmission Operators. When a transmission facility becomes constrained curtailment of Interchange Transactions is required to allow Interchange Transactions of higher priority to be scheduled (Reallocation) or to provide transmission loading relief (Curtailment). An Interchange Transaction is considered for Reallocation or Curtailment if its Transfer Distribution Factor (TDF) exceeds the TLR Curtailment Threshold.

In compliance with the Transmission Service Provider tariffs, Interchange Transactions using Non-firm Point-to-Point Transmission Service are curtailed first (TLR Level 3a and 3b), followed by transmission reconfiguration (TLR Level 4), and then the curtailment of Interchange Transactions using Firm Point-to-Point Transmission Service, Network Integration Transmission Service and service to Native Load (TLR Level 5a and 5b). Curtailment of Firm Point-to-Point Transmission Service shall be accompanied by the comparable curtailment of Network Integration Transmission Service and service to Native Load to the degree that these three Transmission Services contribute to the Constraint.

5.1. Requirements

A methodology, called the Per Generator Method without Counter Flow, or simply the Per Generator Method, has been programmed into the IDC to calculate the portion of parallel flows on any Constrained Facility due to service to Native Load of each Balancing Authority. The following requirements are necessary to assure comparable Reallocation or Curtailment of firm Transmission Service:

- 5.1.1.** The Reliability Coordinator initiating a curtailment shall identify for curtailment all firm Transmission Services (i.e. Point-to-Point, Network Integration and service to Native Load) that contribute to the flow on any Constrained Facility by an amount greater than or equal to the Curtailment Threshold on a pro rata basis.
- 5.1.2.** For Firm Point-to-Point Transmission Services, the Transfer Distribution Factors must be greater than or equal to the Curtailment Threshold.
- 5.1.3.** For Network Integration Transmission Service and service to Native Load, the Generator-To-Load Distribution Factors must be greater than or equal to the Curtailment Threshold.
- 5.1.4.** The Per Generator Method shall assign the amount of Constrained Facility relief that must be achieved by each Balancing Authority's Network Integration Transmission Service or service to Native Load. It shall not specify how the reduction will be achieved.
- 5.1.5.** All Balancing Authorities in the Eastern Interconnection shall be obligated to achieve the amount of Constrained Facility relief assigned to them by the Per Generator Method.
- 5.1.6.** The implementation of the Per Generator Method shall be based on transmission and generation information that is readily available.

5.2. Calculation Method

The calculation of the flow on a Constrained Facility due to Network Integration Transmission Service or service to Native Load shall be based on the Generation Shift Factors (GSFs) of a Balancing Authority's assigned generation and the Load Shift Factors (LSFs) of its native load, relative to the system swing bus. The GSFs shall be calculated from a single bus location in the IDC. The IDC shall report all generators assigned to native load for which the GLDF is greater than or equal to the Curtailment Threshold.

6. Interchange Transaction Reallocation During TLR Levels 3a and 5a

Introduction

This section provides the details for implementing TLR Levels 3a and 5a, both of which provide a means for Reallocation of Transmission Service.

TLR Level 3a accomplishes Reallocation by curtailing Interchange Transactions using Non-firm Point-to-Point Transmission Service to allow Interchange Transactions using higher priority Non-firm or Firm Point-to-Point Transmission Service to start. (See **Requirement 2.3, “TLR Level 3a.”**) When a TLR Level 3a is in effect, Reliability Coordinators shall reallocate Interchange Transactions according to the Transactions’ Transmission Service Priorities. Reallocation also includes the orderly reloading of Transactions by priority when conditions permit curtailed Transactions to be reinstated.

TLR Level 5a accomplishes Reallocation by curtailing Interchange Transactions using Firm Point-to-Point Transmission Service on a pro-rata basis to allow new Interchange Transactions using Firm Point-to-Point Transmission Service to begin, also on a pro-rata basis. (See **Requirement 2.6, “TLR Level 5a.”**)

6.1. Requirements

The basic requirements for Transaction Reallocation are as follows:

- 6.1.1.** When identifying transactions for Reallocation the Reliability Coordinator shall normally only involve Curtailments of Interchange Transactions using Non-firm Point-to-Point Transmission Service during TLR 3a. However, Reallocation may be used during TLR 5a to allow the implementation of additional Interchange Transactions using Firm Transmission Service on a pro-rata basis.
- 6.1.2.** When identifying transactions for Reallocation, the Reliability Coordinator shall only consider those Interchange Transactions at or above the Curtailment Threshold for which a TLR 2 or higher is called.
- 6.1.3.** When identifying transactions for Reallocation, the Reliability Coordinator shall displace Interchange Transactions utilizing lower priority Transmission Service with Interchange Transactions utilizing higher Transmission Service Priority.
- 6.1.4.** When identifying transactions for Reallocation, the Reliability Coordinator shall not curtail Interchange Transactions using Non-firm Transmission Service to allow the start or increase of another transaction having the same Non-Firm Transmission Service Priority (marginal “bucket”).
- 6.1.5.** When identifying transactions for Reallocation, the Reliability Coordinator shall reload curtailed Interchange Transactions prior to starting new or increasing existing Interchange Transactions.
- 6.1.6.** Interchange Transactions whose tags were submitted prior to the TLR 2 or 3a being called, but were subsequently held from starting because they failed to meet the approved tag submission deadline for Reallocation (see Section 6.2, “Communications and Timing Requirements”), shall be considered to have been curtailed and thus would be eligible for reload at the same time as the curtailed Interchange Transaction.

- 6.1.7.** The Reliability Coordinator shall reload or start all eligible Transactions on a pro-rata basis.
- 6.1.8.** Interchange Transactions whose tags meet the approved tag submission deadline for Reallocation (see Section 6.2, “Communications and Timing Requirements”) shall be considered for Reallocation for the upcoming hour. (However, Interchange Transactions using Firm Point-to-Point Transmission Service shall be allowed to start as scheduled.) Interchange Transactions whose tags are submitted to the IDC after the approved tag submission deadline for Reallocation shall be considered for Reallocation the following hour. This applies to Interchange Transactions using either Non-firm Point-to-Point Transmission Service or Firm Point-to-Point Transmission Service. If an Interchange Transaction using Firm Interchange Transaction is submitted after the approved tag submission deadline and after the TLR is declared, that Transaction shall be held and then allowed to start in the upcoming hour.

It should be noted that calling a TLR 3a does not necessarily mean that Interchange Transactions using Non-firm Transmission Service will always be curtailed the next hour. However, TLR Levels 3a and 5a trigger the approved tag submission deadline for Reallocation requirements and allow for a coordinated assessment of all Interchange Transactions tagged to start the upcoming hour.

6.2. Communication and Timing Requirements

The following timeline shall be utilized to support Reallocation decisions during TLR Levels 3a or 5a. See Figures 2 and 3 for a depiction of the Reallocation Time Line.

- 6.2.1. Time Convention.** In this document, the beginning of the current hour shall be referenced as 00:00. The beginning of the next hour shall be referenced as 01:00. The end of the next hour shall be referenced as 02:00. See Figure 1.

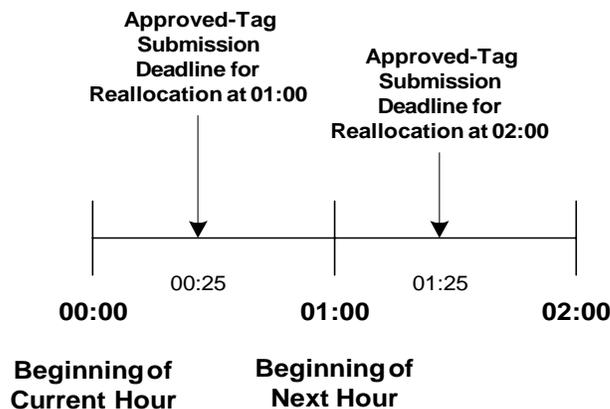


Figure 1 - Timeline showing Approved-tag Submission Deadline for Reallocation

- 6.2.2. Approved tag submission deadline for Reallocation** Reliability Coordinators shall consider all approved Tags for Interchange Transactions at or above the Curtailment Threshold that have been submitted to the IDC by 00:25 for Reallocation at 01:00. See Figure 1. However, Interchange Transactions using Firm Point-to-Point Transmission Service will be allowed to start as scheduled.
 - 6.2.2.1.** Reliability Coordinators shall consider all approved tags submitted to the IDC beyond these deadlines for Reallocation at 02:00 (for both Firm and Non-firm Point-to-Point Transmission Service). However, these Interchange Transactions will not be allowed to start or increase at 01:00.
 - 6.2.2.2.** The approved tag submission deadline for Reallocation shall cease to be in effect as soon as the TLR level is reduced to 1 or 0.

6.2.3. Off-hour Transactions. Interchange Transactions with a start time other than $xx:00$ shall be considered for Reallocation at $xx+1:00$. For example, an Interchange Transaction with a start time of 01:05 and whose Tag was submitted at 00:15 will be considered for Reallocation at 02:00.

6.2.4. Tag Evaluation Period. Balancing Authorities and Transmission Providers shall evaluate all tags submitted for Reallocation and shall communicate approval or rejection by 00:25.

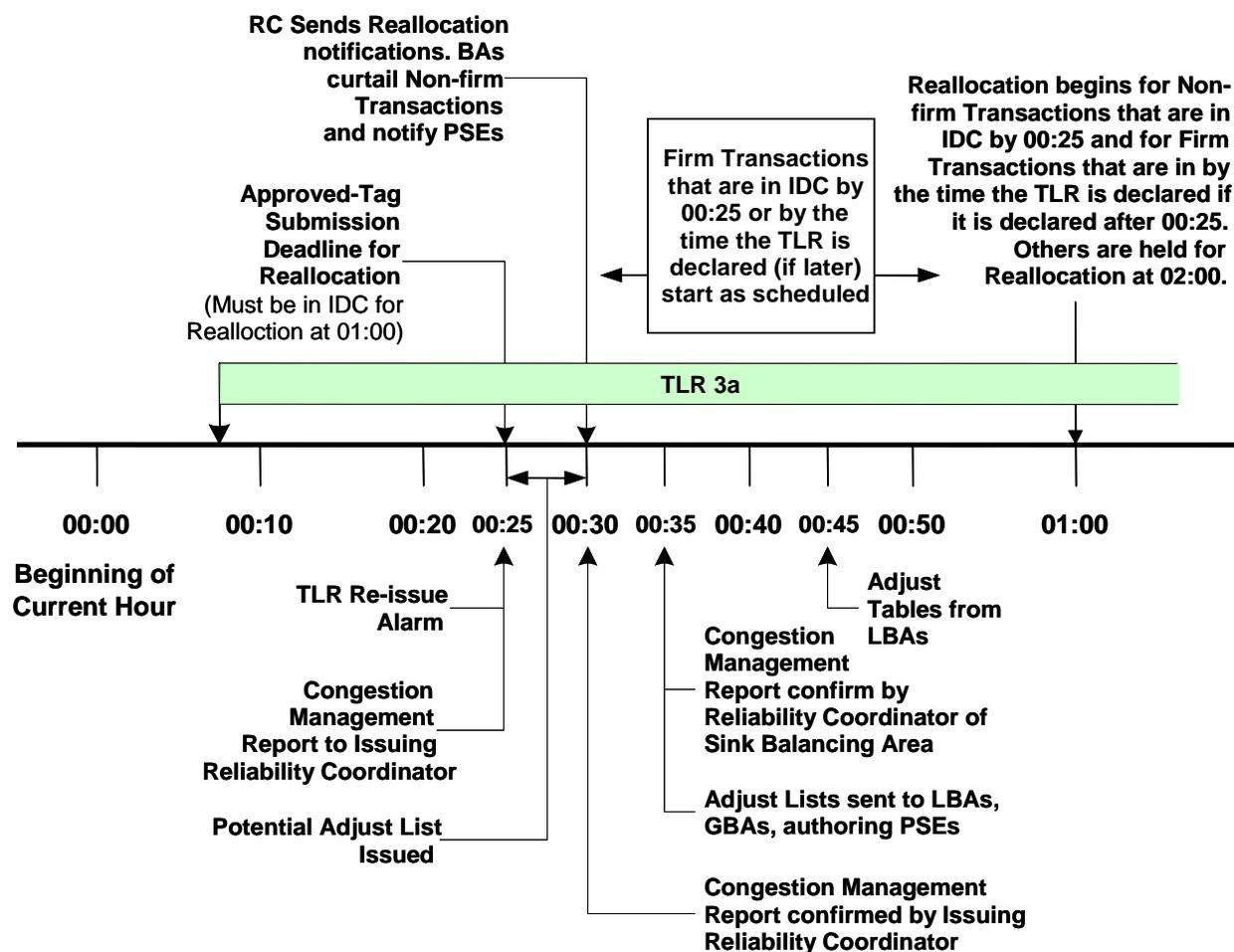


Figure 2 — Reallocation Timing for TLR 3a Called at 00:08

6.2.5. Collective Scheduling Assessment Period. At 00:25, the initiating Reliability Coordinator (the one who called and still has a TLR 3a or 5a in effect) shall run the IDC to obtain a three-part list of Interchange Transactions including their transaction status:

6.2.5.1. Interchange Transactions that may start, increase, or reload shall have a status of PROCEED, and

6.2.5.2. Interchange Transactions that must be curtailed or Interchange Transactions whose tags were submitted prior to the TLR 2 or higher

being declared but were not permitted to start or increase shall have a status of CURTAILED, and

6.2.5.3. Interchange Transactions that are entered into the IDC after 00:25 shall have a status of HOLD and be considered for Reallocation at 02:00. Also, Interchange Transactions using Non-firm Point-to-Point Transmission Service submitted after TLR 2 or higher was declared (“post-tagged”) but have not been allowed to start shall retain the HOLD status until given permission to PROCEED or E-Tag expires. (Note: TLR Level 2 does not hold Interchange Transactions using Firm Point-to-Point Transmission Service).

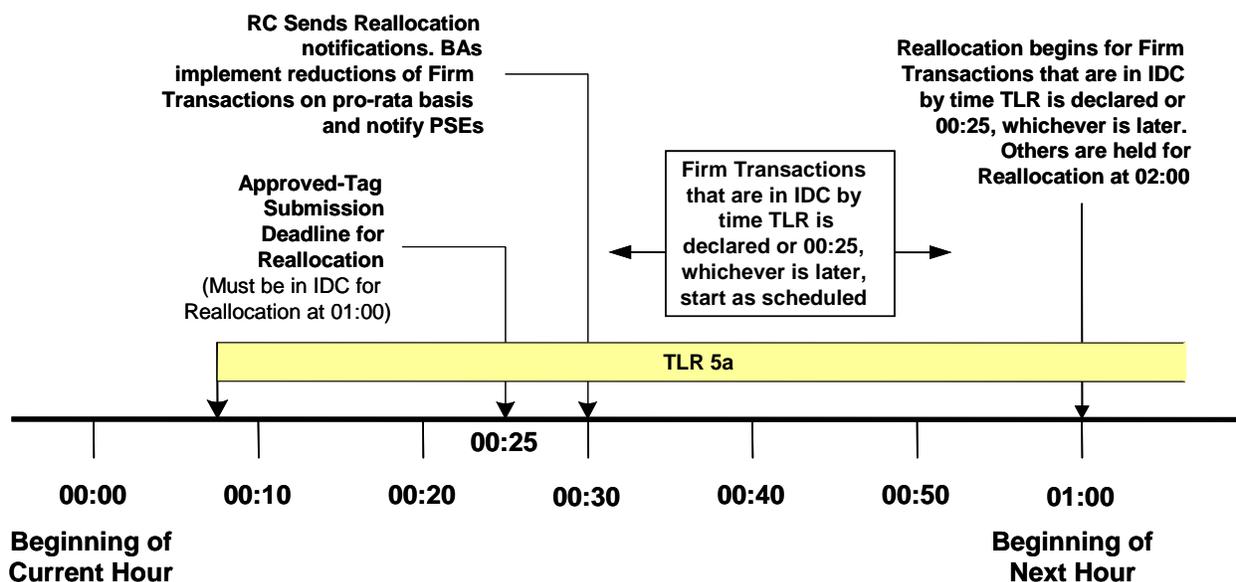


Figure 3 — Reallocation timing for TLR 5a called at 00:08.

6.2.5.4. The initiating Reliability Coordinator shall communicate the list of Interchange Transactions to the appropriate sink Reliability Coordinators via the IDC, who shall in turn communicate the list to the Sink Balancing Authorities at 00:30 for appropriate actions to implement Interchange Transactions (CURTAIL, PROCEED or HOLD). The IDC will prompt the initiating Reliability Coordinator to input the necessary information (i.e., maximum flowgate loading and curtailment requirement) into the IDC by 00:25.

6.2.5.5. Subsequent required reports before 01:00 shall allow the Reliability Coordinators to include those Interchange Transactions whose tags were submitted to the IDC after the Approved-Tag Submission Time for Reallocation and were given the HOLD status (not permitted to PROCEED). Transactions at or above the Curtailment Threshold that are not indicated as “PROCEED” on Reload/Reallocation Report shall not be permitted to start or increase the next hour.

Discussion: Note that TLR 2 does not initiate the approved tag submission deadline for Reallocation, but a TLR3a or 5a does. It is, however, important to recognize the time when a TLR 2 is called, where applicable, to determine the status of a held transaction – “CURTAILED” if tagged before the TLR was called but “HOLD” if tagged after the TLR was called.

6.2.5.6. In running the IDC, the Reliability Coordinator shall have an option to specify the maximum loading of the Constrained Facility by all Interchange Transactions using Point-to-Point Transmission Service.

Discussion: This allows the Reliability Coordinator to take into consideration SOLs or IROLs and changes in Transactions using other than Point-to-Point service taken under the Open Access Transmission Tariff. This option is needed to avoid loading the Constrained Facility to its limit with known Interchange Transactions while other factors push the facility into a SOL or IROL violation and hence triggering the declaration of a TLR 3b or 5b.

6.2.5.7. Notification of Interchange Transaction status shall be provided from the IDC to the Reliability Coordinators via an IDC Report. The Reliability Coordinators shall communicate this information to the Balancing Authorities and Transmission Operators.

Additional reporting and communications details on information posted from the IDC to the NERC TLR website are contained in Appendix E.

6.2.6. **Customer Preferences on Timing to Call TLR 3a or 5a.** Reliability Coordinators shall leave a TLR 2 and call a TLR 3a as soon as possible (but no later than 30 minutes) to initiate the Approved-Tag Submission Deadline and start reallocating Transactions. Nevertheless, recognizing the approved tag submission deadline for Reallocation, from a Transmission Customer perspective, it is preferable that the Reliability Coordinator call a TLR 3a within a certain time period to allow for tag preparation and submission. See Figure 4.

Discussion: A Reliability Coordinator calls a TLR 2 or 3a whenever it deems necessary to indicate that a transmission facility is approaching its SOL or IROL. It is envisioned, though not required, that a TLR 2 or 3a is preceded by a period of a TLR 1 declaration, hence Transmission Customers should normally have advance notice of a potential constraint. For example, a TLR 3a initiated during the period 01:00 to 01:25 would allow the Purchasing-Selling Entity to submit a Tag for entry into the IDC by the Approved-Tag Submission Deadline for Reallocation at 02:00. See Figure 4. However, the preferred time period to declare a TLR 3a or 5a would be between 00:40 (when tags for Next Hour Market have been submitted) and 01:15. This will allow the Transmission Customers a range of 15 to 35 minutes to prepare and submit tags. (Note: In this situation, the Reliability Coordinator would need to reissue the TLR 3a at 01:00.)

It must be emphasized that the preferred time period is not a requirement, and should not in any way impede a Reliability Coordinator’s ability to declare a TLR 3a, 3b, 4, 5a, or 5b whenever the need arises.

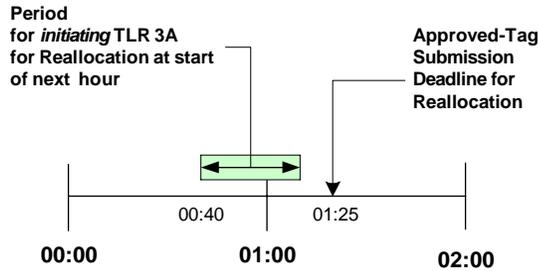


Figure 4. "Ideal" time for issuing TLR 3a for Reallocation at 02:00.

7. Interchange Transaction Curtailments During TLR Level 3b

Introduction

This section provides the details for implementing TLR Level 3b, which curtails Interchange Transactions using Non-firm Point-to-Point Transmission Service to assist the Reliability Coordinator to recover from SOL or IROL violations.

TLR Level 3b curtails Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold. (See **Requirement 2.4, "TLR Level 3b."**). Furthermore, *all* new Interchange Transactions using Non-firm Point-to-Point Transmission Service that are at or above the Curtailment Threshold during the TLR 3b implementation period are halted or held. Transactions using Firm Point-to-Point Transmission Service will be allowed to start if they are submitted to the IDC within specific time limits as explained in Appendix F, "Considerations for Interchange Transactions using Firm Point-to-Point Transmission Service." Those Interchange Transactions using Firm Point-to-Point Transmission Service that are not submitted to the IDC within these time limits will be held.

Requirements

- 7.1. The Reliability Coordinator shall be allowed to call a TLR 3b at any time to help mitigate a SOL or IROL violation.
- 7.2. The Reliability Coordinator shall consider only those Interchange Transactions at or above the Curtailment Threshold for curtailment, holding, or halting.
- 7.3. The Reliability Coordinator shall curtail existing Interchange Transactions using Non-firm Point-to-Point Transmission Service as necessary to provide the required relief on the Constrained Facility.
- 7.4. The Reliability Coordinator shall curtail additional Interchange Transactions using Non-firm Point-to-Point Transmission Service to provide transmission capacity for Interchange Transactions using Firm Point-to-Point Transmission Service if those Interchange Transactions using Firm Point-to-Point Transmission Service are scheduled to start during the current hour or the following hour.
- 7.5. The Reliability Coordinator shall not allow existing Interchange Transactions using Non-firm Point-to-Point Transmission Service that are not curtailed to increase (they may flow at the same or reduced level).
- 7.6. The Reliability Coordinator shall not reallocate Interchange Transactions using Non-firm Point-to-Point Transmission Service during a TLR 3b.

- 7.7.** The Reliability Coordinator shall allow Interchange Transactions using Firm Point-to-Point Transmission Service to start as explained in Appendix F, “Considerations for Interchange Transactions using Firm Point-to-Point Transmission Service.”
- 7.8.** The Reliability Coordinator shall progress to TLR Level 5b as necessary if there is still insufficient transmission capacity for Interchange Transactions using Firm Point-to-Point Transmission Service to start as scheduled after all Interchange Transactions using Non-firm Point-to-Point Transmission Service have been curtailed.
- 7.9.** The IDC shall issue ADJUST Lists to the Generation and Load Balancing Authority Areas and the Purchasing-Selling Entity who submitted the tag. The ADJUST List will include:
 - 7.9.1.** Interchange Transactions using Non-firm Point-to-Point Transmission Service that are to be curtailed, halted, or held during current and next hours.
 - 7.9.2.** Interchange Transactions using Firm Point-to-Point Transmission Service that were entered after 00:25 or issuance of TLR 3b (see Case 3 in Appendix F).
- 7.10.** The Sink Balancing Authority shall send the ADJUST Lists back to the IDC as soon as possible to ensure the most accurate calculations for actions subsequent to the TLR 3b being called.
- 7.11.** The Reliability Coordinator shall be allowed to call a TLR Level 3a as soon as the SOL or IROL violation that caused the TLR 3b to be called has been mitigated.
 - 7.11.1.** If the TLR Level 3a is called before the hour 01, then a Reallocation shall be computed for the start of that hour.
 - 7.11.2.** Transactions must be in the IDC by the Approved-tag Submission Deadline for Reallocation (see Requirement 6.2).

Appendices for Transmission Loading Relief Standard

Appendix A. Transaction Management and Curtailment Process.

Appendix B. Transaction Curtailment Formula.

Appendix C. Sample NERC Transmission Loading Relief Procedure Log.

Appendix D. Examples for Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service.

Appendix E. How the IDC Handles Reallocation.

Section E1: Summary of IDC Features that Support Transaction Reloading/Reallocation.

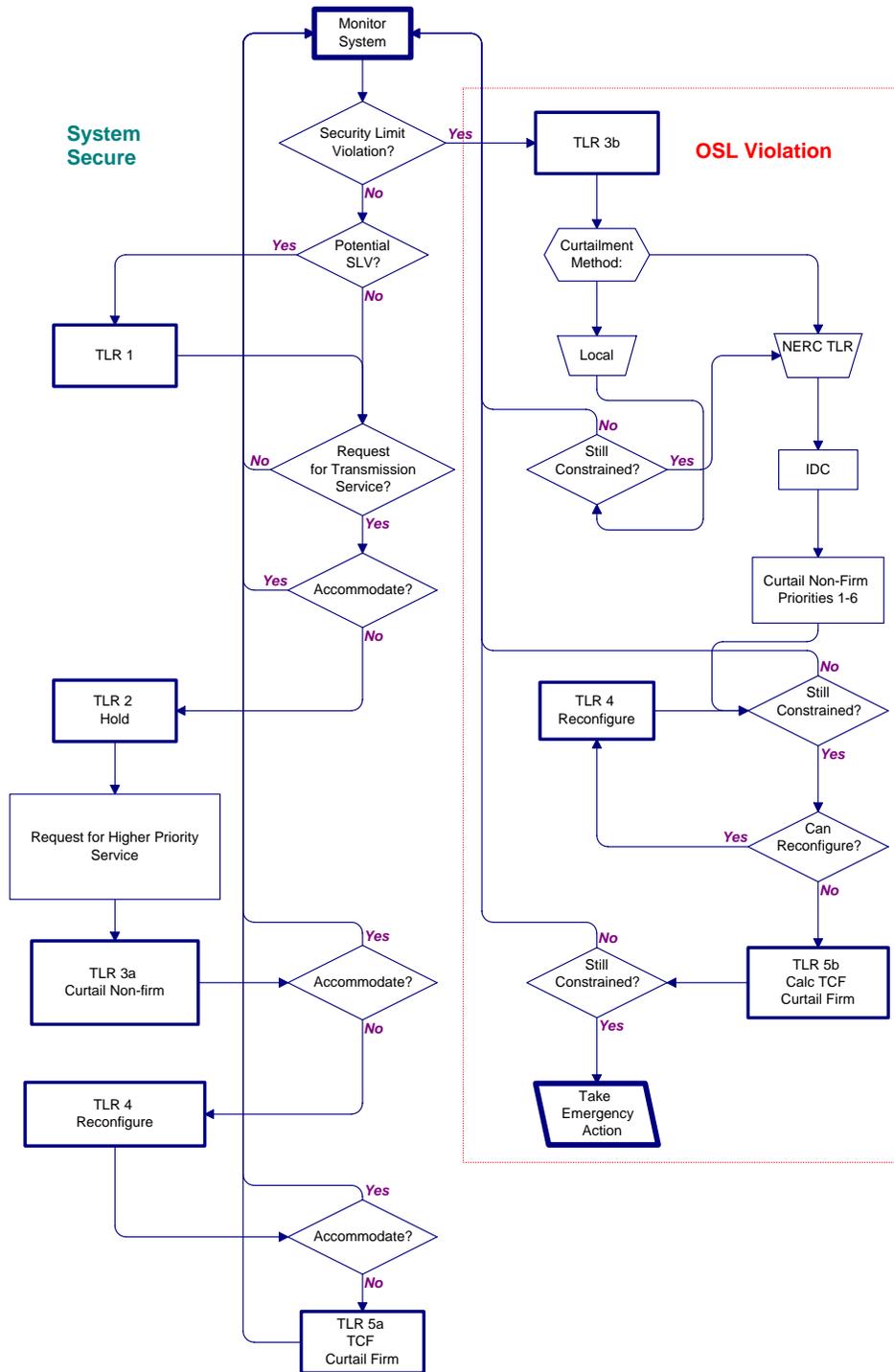
Section E2: Timing Requirements.

Appendix F. Considerations for Interchange Transactions using Firm Point-to-Point Transmission Service.

Appendix G. Examples of On-Path and Off-Path Mitigation.

Appendix A. Transaction Management and Curtailment Process

This flowchart depicts an overview of the Transaction Management and Curtailment process. Detailed decisions are not shown.



Appendix B. Transaction Curtailment Formula

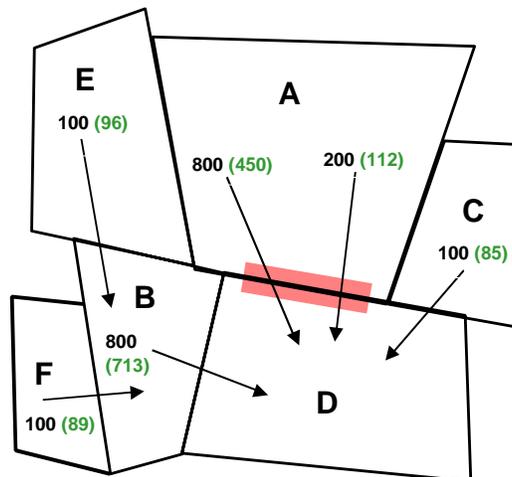
Example

This example is based on the premise that a transaction should be curtailed in proportion to its Transfer Distribution Factor on the Constraints. Its effect on the interface is a combination of its size in MW and its effect based on its distribution factor.

Column	Description
1. Initial Transaction	Interchange Transaction before the TLR Procedure is implemented.
2. Distribution Factor	Proportional effect of the Transaction over the constrained interface due to the physical arrangement and impedance of the transmission system.
3. Impact on the Interface	Result of multiplying the Transaction MW by the distribution factor. This yields the MW that flow through the constrained interface from the Transaction. Performing this calculation for each Transaction yields the total flow through the constrained interface from all the Interchange Transactions. In this case, 760 MW.
4. Impact Weighting Factor	“Normalization” of the total of the Distribution Factors in Column 2. Calculated by dividing the Distribution Factor for each Transaction by the total of the Distribution Factors.
5. Weighted Maximum Interface Reduction	Multiplying the Impact on the Interface from each Transaction by its Impact Weighting Factor yields a new proportion that is a combination of the MW Impact on the Interface and the Distribution Factor.
6. Interface Reduction	Multiplying the amount needed to reduce the flow over the constrained interface (280 MW) by the normalization of the Weighted Maximum Interface Reduction yields the actual MW reduction that each Transaction must <i>contribute</i> to achieve the total reduction.
7. Transaction Reduction	Now divide by the Distribution Factor to see how much the Transaction must be reduced to yield the result calculated in Column 7. Note that the reductions for the first two Interchange Transactions (A-D (1) and A-D (2)) are in proportion to their size since their distribution factors are equal.
8. New Transaction Amount	Subtracting the Transaction Reduction from the Initial Transaction yields the New Transaction Amount.
9. Adjusted Impact on Interface	A check to ensure the new constrained interface MW flow has been reduced to the target amount.

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Allocation based on Weighted Impact									
Transaction ID	1 Initial Transaction	2 Distribution Factor	3 (1)*(2) Impact On Interface	4 (2)/(2TOT) Impact weighting factor	5 (3)*(4) Weighted Max Interface Reduction	6 (5)*(Relief Requested)/(5 Tot) Interface Reduction	7 (6)/(2) Transaction Reduction	8 (1)-(7) New Transaction Amount	9 (8)*(2) Adjusted Impact On Interface
Example 1									
A-D(1)	800	0.6	480	0.34	164.57	209.73	349.54	450.46	270.27
A-D(2)	200	0.6	120	0.34	41.14	52.43	87.39	112.61	67.57
B-D	800	0.15	120	0.09	10.29	13.11	87.39	712.61	106.89
C-D	100	0.2	20	0.11	2.29	2.91	14.56	85.44	17.09
E-B	100	0.05	5	0.03	0.14	0.18	3.64	96.36	4.82
F-B	100	0.15	15	0.09	1.29	1.64	10.92	89.08	13.36
	2100	1.75	760		219.71	280.00	553.45	1546.55	480.00
Example 2									
A-D(1)	1000	0.6	600	0.52	313.04	262.16	436.93	563.07	337.84
B-D	800	0.15	120	0.13	15.65	13.11	87.39	712.61	106.89
C-D	100	0.2	20	0.17	3.48	2.91	14.56	85.44	17.09
E-B	100	0.05	5	0.04	0.22	0.18	3.64	96.36	4.82
F-B	100	0.15	15	0.13	1.96	1.64	10.92	89.08	13.36
	2100	1.15	760		334.35	280.00	553.45	1546.55	480.00
Example 3									
A-D(1A)	200	0.6	120	0.17	20.28	52.43	87.39	112.61	67.57
A-D(1B)	200	0.6	120	0.17	20.28	52.43	87.39	112.61	67.57
A-D(1C)	200	0.6	120	0.17	20.28	52.43	87.39	112.61	67.57
A-D(1D)	200	0.6	120	0.17	20.28	52.43	87.39	112.61	67.57
A-D(2)	200	0.6	120	0.17	20.28	52.43	87.39	112.61	67.57
B-D	800	0.15	120	0.04	5.07	13.11	87.39	712.61	106.89
C-D	100	0.2	20	0.06	1.13	2.91	14.56	85.44	17.09
E-B	100	0.05	5	0.01	0.07	0.18	3.64	96.36	4.82
F-B	100	0.15	15	0.04	0.63	1.64	10.92	89.08	13.36
	2100	3.55	760		108.31	280.00	553.45	1546.55	480.00



**Appendix D. Examples for Parallel Flow Calculation Procedure
for Reallocating or Curtailing Firm Transmission Service**

The NERC “**Parallel Flow Calculation Procedure Reference Document**” provides additional information about the criteria used to include generators in the IDC calculation process.

Example of Results of Calculation Method

An example of the output of the IDC calculation of curtailment of firm Transmission Service is provided below for the specific Constrained Facility identified in the *Book of Flowgates* as Flowgate 1368. In this example, a total Firm Point-to-Point contribution to the Constrained Facility, as calculated by the IDC, is assumed to be 21.8 MW.

The table below presents a summary of each Balancing Authority’s responsibility to provide relief to the Constrained Facility due to its Network Integration Transmission Service and service to Native Load contribution to the Constrained Facility. In this example, Balancing Authority LAGN would be requested to curtail 17.3 MW of its total of 401.1 MW of flow contribution on the Constrained Facility. See the “**Parallel Flow Calculation Procedure Reference Document**” for additional details regarding the information illustrated in the table (e. g. Scaled P Max and Flowgate NNative Load MW).

In summary, Interchange transactions would be curtailed by a total of 21.8 MW and Network Integration Transmission Service and service to Native Load would be curtailed by a total of 178.2 MW by the five Balancing Authorities identified in the table. These curtailments would provide a total of 200.0 MW of relief to the Constrained Facility.

Sink Reliability Coordinator	Service Point	Scaled P Max	Flowgate NNative Load MW	Current NNative Load Relief	NNative Load Responsibility		NNative Load Responsibility Acknowledgement	
					Inc/Dec	Current Hr	Acknowledge Time	Total MW Resp.
EES	EES	8429.7	2991.4	0.0	128.9	128.9	13:44	128.9
EES	LAGN	1514.0	718.6	0.0	31.0	31.0	13:44	31.0
SOCO	SOCO	5089.2	401.1	0.0	17.3	17.3	13:44	17.3
SWPP	CLEC	235.7	18.0	0.0	0.8	0.8	13:42	0.8
SWPP	LEPA	22.8	4.1	0.0	0.2	0.2	13:42	0.2
Total				0.0				

Appendix E. How the IDC Handles Reallocation

The IDC algorithms reflect the Reallocation and reloading principles in this Appendix, as well as the reporting requirements, and status display. The IDC will obtain the Tag Submittal Time from the Tag Authority and post the Reloading/Reallocation information to the NERC TLR website.

A summary of IDC features that support the Reallocation process is provided in Attachment E1. Details on the interface and display features are provided in Attachment E2. Refer to Version 1.7.095 NERC Transaction Information Systems Working Group (TISWG) *Electronic Tagging Functional Specification* for details about the E-Tag system.

E1. Summary of IDC Features that Support Transaction Reloading/Reallocation

The following is a summary of IDC features and E-Tag interface that support Reloading/Reallocation:

Information posted from IDC to NERC TLR website.

1. Restricted directions (all source/sink combinations that impact a Constrained Facility(ies) with TLR 2 or higher) will be posted to the NERC TLR website and updated as necessary.
2. TLR Constrained Facility status and Transfer Distribution Factors will continue to be posted to NERC TLR website.
3. Lowest priority of Interchange Transactions (marginal “bucket”) to be Reloaded/Reallocated next-hour on each TLR Constrained Facility will be posted on NERC TLR website. This will provide an indication to the market of priority of Interchange Transactions that may be Reloaded/Reallocated the following hours.

IDC Logic, IDC Report, and Timing

1. The Reliability Coordinator will run the IDC the Reloading/Reallocation report at approximately 00:26. The IDC will prompt the Reliability Coordinator to enter a maximum loading value. The IDC will alarm if the Reliability Coordinator does not enter this value and issue a report by 00:30 or change from TLR 3a Level. The Report will be distributed to Balancing Authorities and Transmission Operators at 00:30. This process repeats every hour as long as the approved tag submission deadline for Reallocation is in effect (or until the TLR level is reduced to 1 or 0).
2. For Interchange Transactions in the restricted directions, tags must be submitted to the IDC by the approved tag submission deadline for Reallocation to be considered for Reallocation next-hour. The time stamp by the Tag Authority is regarded the official tag submission time.
3. Tags submitted to IDC after the approved tag submission deadline for Reallocation will not be allowed to start or increase but will be considered for Reallocation the next hour.
4. Interchange Transactions in restricted directions that are not indicated as “PROCEED” on the Reload/Reallocation Report will not be permitted to start or increase next hour.

Reloading/Reallocation Transaction Status

Reloading/Reallocation status will be determined by the IDC for all Interchange Transactions. The Reloading/Reallocation status of each Interchange Transaction will be listed on IDC reports and NERC TLR website as appropriate. An Interchange Transaction is considered to be in a restricted direction if it is at or above the Curtailment Threshold. Interchange Transactions below the Curtailment Threshold are unrestricted and free to flow subject to all applicable Reliability Standards and tariff rules.

1. **HOLD.** Permission has not been given for Interchange Transaction to start or increase and is waiting for the next Reloading/Reallocation evaluation for which it is a candidate. Interchange Transactions with E-tags submitted to the Tag Authority prior to TLR 2 or higher being declared (pre-tagged) will change to CURTAILED Status upon evaluation that does not permit them to start or increase. Transactions with E-tags submitted to Tag Authority after TLR 2 or higher was declared (post-tagged) will retain HOLD Status until given permission to proceed or E-Tag expires.
2. **CURTAILED.** Transactions for which E-Tags were submitted to Tag Authority prior to TLR 2 or higher being declared (pre-tagged) and ordered to be curtailed totally, curtailed partially, not permitted to start, or not permitted to increase. Interchange Transactions (pre-tagged or post-tagged) that were flowing and ordered to be reduced or totally curtailed. The Balancing Authority will indicate to the IDC through the E-Tag adjustment table the Interchange Transaction's curtailed values.
3. **PROCEED:** Interchange Transaction is flowing or has been permitted to flow as a result of Reloading/Reallocation evaluation. The Balancing Authority will indicate through the E-Tag adjustment table to IDC if Interchange Transaction will reload, start, or increase next-hour per Purchasing-Selling Entity's energy schedule as appropriate.

Reallocation/Reloading Priorities

1. Interchange Transaction candidates are ranked for loading and curtailment by priority as per Appendix 9C1, Section E, "Principles for Mitigating Constraints On and Off the Contract Path"]. This is called the "Constrained Path Method," or CPM. (secondary, hourly, daily, ... firm etc). Interchange Transactions are curtailed and loaded pro-rata within priority level per TLR algorithm.
2. Reloading/Reallocation of Interchange Transactions are prioritized first by priority per CPM. E-Tags must be submitted to the IDC by the approved tag submission deadline for Reallocation of the hour during which the Interchange Transaction is scheduled to start or increase to be considered for Reallocation.
3. During Reloading/Reallocation, Interchange Transactions using lower priority Transmission Service will be curtailed pro-rata to allow higher priority transactions to reload, increase, or start. Equal priority Interchange Transactions will not reload, start, or increase by pro-rata Curtailment of other equal priority Interchange Transactions.
4. Reloading of Interchange Transactions using Non-firm Transmission Service with CURTAILED Status will take precedence over starting or increasing of Interchange Transactions using Non-firm Transmission Service of the same priority with PENDING Statuses.
5. Interchange Transactions using Firm Point-to-Point Transmission Service will be allowed to start as scheduled under TLR 3a as long as their E-Tag was received by the IDC by the approved tag submission deadline for Reallocation of the hour during which the Interchange Transaction is due to start or increase, regardless of whether the E-tag was submitted to the Tag Authority prior to TLR 2 or higher being declared or not. If this is the initial issuance of the TLR 3a, Interchange Transactions using Firm Point-to-Point Transmission Service will be allowed to start as scheduled as long as their E-Tag was received by the IDC by the time the TLR is declared.

Total Flow Value on a Constrained Facility for Next Hour

1. The Reliability Coordinator will calculate the change in net flow on a Constrained Facility due to Reallocation for the next hour based on:

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- Present constrained facility loading, present level of Interchange Transactions, and Balancing Authorities NNative Load responsibility (TLR Level 5a) impacting the Constrained Facility,
 - SOLs or IROLs, known interchange impacts and Balancing Authority NNative Load responsibility (TLR Level 5a) on the Constrained Facility the next hour, and
 - Interchange Transactions scheduled to begin the next hour.
2. The Reliability Coordinator will enter a maximum loading value for the constrained facility into the IDC as part of issuing the Reloading/Reallocation report.
 3. The Reliability Coordinator is allowed to call for TLR 3a or 5a when approaching a SOL or IROL to allow maximum transactional flow next hour, and to manage flows without violating transmission limits.
 4. The simultaneous curtailment and Reallocation for a Constrained Facility is allowed. This reduces the flow over the Constrained Facility while allowing Interchange Transactions using higher priority Transmission Service to start or increase the next hour. This may be used to accommodate change in flow next-hour due to changes other than Point-to-Point Interchange Transactions while respecting the priorities of Interchange Transactions flowing and scheduled to flow the next hour. The intent is to reduce the need for using TLR 3b, which prevents new Interchange Transactions from starting or increasing the next hour.
 5. The Reliability Coordinator must allow Interchange Transactions to be reloaded as soon as possible. Reloading must be in an orderly fashion to prevent a SOL or IROL violation from (re)occurring and requiring holding or curtailments in the restricted direction.

E2. Timing Requirements

TLR Levels 3a and 5a Issuing/Processing Time Requirement

1. In order for the IDC to be reasonably certain that a TLR Level 3a or 5a re-allocation/reloading report in which all tags submitted by the approved tag submission deadline for Reallocation are included, the report must be generated no earlier than 00:25 to allow the 10-minute approval time for Transactions that start next hour.
2. In order to allow a Reliability Coordinator to declare a TLR Level 3a or 5a at any time during the hour, the TLR declaration and Reallocation/Reloading report distribution will be treated as independent processes by the IDC. That is, a Reliability Coordinator may declare a TLR Level 3a or 5a at any time during the course of an hour. However, if a TLR Level 3a or 5a is declared for the next hour prior to 00:25 (see Figure 5 at right), the Reallocation/Reloading report that is generated will be made available to the issuing Reliability Coordinator only for previewing purposes, and cannot be distributed to the other Reliability Coordinators or the market. Instead, the issuing Reliability Coordinator will be reminded by an IDC alarm at 00:25 to generate a new Reallocation/Reloading report that will include all tags submitted prior to the approved tag submission deadline for Reallocation.
3. A TLR Level 3a or 5a Reallocation/Reloading report must be confirmed by the issuing Reliability Coordinator prior to 00:30 in order to provide a minimum of 30 minutes for the Reliability Coordinators with tags sinking in its Reliability Area to coordinate the Reallocation and Reloading with the Sink Balancing Authorities. This provides only 5 minutes (from 00:25 to 00:30) for the issuing Reliability Coordinator to generate a Reallocation/Reloading report, review it, and approve it.
4. The TLR declaration time will be recorded in the IDC for evaluating transaction sub-priorities for Reallocation/Reloading purposes (see Subpriority Table, in the **IDC Calculations and Reporting** section below).

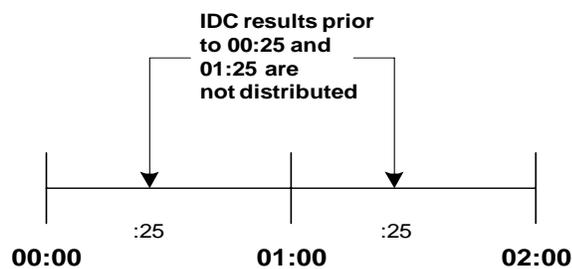


Figure 5 - IDC report may be run prior to 00:25, but results are not distributed.

Re-Issuing of a TLR Level 2 or Higher

Each hour, the IDC will automatically remind the issuing Reliability Coordinator (via an IDC alarm) of a TLR level 2 or higher declared in the previous hour or earlier about re-issuing the TLR. The purpose of the reminder is to enable the Reliability Coordinator to Reallocate or reload currently halted or curtailed Interchange Transactions next hour. The reminder will be in the form of an alarm to the issuing Reliability Coordinator, and will take place at 00:25 so that, if the Reliability Coordinator re-issues the TLR as a TLR level 3a or 5a, all tags submitted prior to the approved tag submission deadline for Reallocation are available in the IDC.

IDC Assistance with Next Hour Point-to-Point Transactions

In order to assist a Reliability Coordinator in determining the MW relief required on a Constrained Facility for the next hour for a TLR level 3a or 5a, the IDC will calculate and present the total MW impact of all currently flowing and scheduled Point-to-Point Transactions for the next hour. In order to assist a Reliability Coordinator in determining the MW relief required on a Constrained Facility for the next hour during a TLR level 5a, the IDC will calculate and present the total MW impact of all currently flowing and scheduled Point-to-Point Transactions for the next hour as well as Balancing Authority with flows due to service to Network Customers and Native Load. The Reliability Coordinator will then be requested to provide the total incremental or decremental MW amount of flow through the Constrained Facility that can be allowed for the next hour. The value entered by the Reliability Coordinator and the

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IDC-calculated amounts will be used by the IDC to identify the relief/reloading amounts (delta incremental flow value) on the constrained facility. The IDC will determine the Transactions to be reloaded, reallocated, or curtailed to make room for the Transactions using higher priority Transmission Service. The following examples show the calculation performed by IDC to identify the “delta incremental flow:”

Example 1

Flow to maintain on Facility	800 MW
Expected flow next hour from Transactions using Point-to-Point Transmission Service	950 MW
Contribution from flow next hour from service to Network customers and Native Load	-100 MW
Expected Net flow next hour on Facility	850 MW
Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation	$850 \text{ MW} - 800 \text{ MW} = 50 \text{ MW}$
Amount to enter into IDC for Transactions using Point-to-Point Transmission Service	$950 \text{ MW} - 50 \text{ MW} = 900 \text{ MW}$

Example 2

Flow to maintain on Facility	800 MW
Expected flow next hour from Transactions using Point-to-Point Transmission Service	950 MW
Contribution from flow next hour from service to Network customers and Native Load	50 MW
Expected Net flow next hour on Facility	1000 MW
Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation	$1000 \text{ MW} - 800 \text{ MW} = 200 \text{ MW}$
Amount to enter into IDC for Transactions using Point-to-Point Transmission Service	$950 \text{ MW} - 200 \text{ MW} = 750 \text{ MW}$

Example 3

Flow to maintain on Facility	800 MW
Expected flow next hour from Transactions using Point-to-Point Transmission Service	950 MW
Contribution from flow next hour from service to Network customers and Native Load	-200 MW
Expected Net flow next hour on Facility	750 MW
Amount of Transactions using Point-to-Point Transmission Service to hold for Reallocation	$750 \text{ MW} - 800 \text{ MW} = -50 \text{ MW}$ None are held

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For a TLR levels 3b or 5b the IDC will request the Reliability Coordinator to provide the MW requested relief amount on the Constrained Facility, and will not present the current and next hour MW impact of Point-to-Point transactions. The Reliability Coordinator-entered requested relief amount will be used by the IDC to determine the Interchange Transaction Curtailments and flows due to service to Network Customers and Native Load (TLR Level 5b) in order to reduce the SOL or IROL violation on the Constrained Facility by the requested amount.

IDC Calculations and Reporting

At the time the TLR report is processed, the IDC will use all candidate Interchange Transactions for Reallocation that met the approved tag submission deadline for Reallocation plus those Interchange Transactions that were curtailed or halted on the previous TLR action of the same TLR event. The IDC will calculate and present an Interchange Transactions Halt/Curtailment list that will include reload and Reallocation of Interchange Transactions. The Interchange Transactions are prioritized as follows:

1. All Interchange Transactions will be arranged by Transmission Service Priority according to the Constrained Path Method. These priorities range from 1 to 6 for the various non-firm Transmission Service products (TLR levels 3a and 3b). Interchange Transactions using Firm Transmission Service (priority 7) are used only in TLR levels 5a and 5b. Next-Hour Market Service is included at priority 0.
2. In a TLR Level 3a the Interchange Transactions using Non-firm Transmission Service in a given priority will be further divided into four sub-priorities, based on current schedule, current active schedule (identified by the submittal of a tag ADJUST message), next-hour schedule, and tag status. Solely for the purpose of identifying which Interchange Transactions to be loaded under a TLR 3a, various MW levels of an Interchange Transaction may be in different sub-priorities. The sub-priorities are shown in the following table:

Priority	Purpose	Explanation and Conditions
S1	To allow a flowing Interchange Transaction to maintain or reduce its current MW amount in accordance with its energy profile.	The MW amount is the lowest between currently flowing MW amount and the next-hour schedule. The currently flowing MW amount is determined by the e-tag ENERGY PROFILE and ADJUST tables. If the calculated amount is negative, zero is used instead.
S2	To allow a flowing Interchange Transaction that has been curtailed or halted by TLR to reload to the <i>lesser</i> of its current-hour MW amount or next-hour schedule in accordance with its energy profile.	The Interchange Transaction MW amount used is determined through the e-tag ENERGY PROFILE and ADJUST tables. If the calculated amount is negative, zero is used instead.
S3	To allow a flowing Transaction to increase from its current-hour schedule to its next-hour schedule in accordance with its energy profile.	The MW amounts used in this sub-priority is determined by the e-tag ENERGY PROFILE table. If the calculated amount is negative, zero is used instead.

Priority	Purpose	Explanation and Conditions
S4	To allow a Transaction that had never started and was submitted to the Tag Authority after the TLR (level 2 or higher) has been declared to begin flowing (i.e., the Interchange Transaction never had an active MW and was submitted to the IDC <i>after</i> the first TLR Action of the TLR Event had been declared.)	The Transaction would not be allowed to start until all other Interchange Transactions submitted prior to the TLR with the same priority have been (re)loaded. The MW amount used is the sub-priority is the next-hour schedule determined by the e-tag ENERGY PROFILE table.

Examples of Interchange Transactions using Non-firm Transmission Service sub-priority settings begin in the **Transaction Sub-priority Examples** following sections.

3. All Interchange Transactions using Firm Transmission Service will be put in the same priority group, and will be Curtailed/Reallocated pro-rata, independent of their current status (curtailed or halted) or time of submittal with respect to TLR issuance (TLR level 5a). Under a TLR 5a, all Interchange Transactions using Non-firm Transmission Service that is at or above the Curtailment Threshold will have been curtailed and hence sub-prioritizing is not required.

All Interchange Transactions processed in a TLR are assigned one of the following statuses:

- PROCEED: The Interchange Transaction has started or is allowed to start to the next hour MW schedule amount.
- CURTAILED: The Interchange Transaction has started and is curtailed due to the TLR, or it had not started but it was submitted prior to the TLR being declared (level 2 or higher).
- HOLD: The Interchange Transaction had never started and it was submitted after the TLR being declared – the Interchange Transaction is held from starting next hour or the transaction had never started and it was submitted to the IDC after the Approved-Tag Submission Deadline – the Interchange Transaction is to be held from starting next hour and is not included in the Reallocation calculations until following hour.

Upon acceptance of the TLR Transaction Reallocation/reloading report by the issuing Reliability Coordinator, the IDC will generate a report to be sent to NERC that will include the PSE name and Tag ID of each Interchange Transaction in the IDC TLR report. The Interchange Transaction will be ranked according to its assigned status of HOLD, CURTAILED or PROCEED. The reloading/Reallocation report will be made available at NERC’s public TLR website, and it is NERC’s responsibility to format and publish the report.

Tag Reloading for TLR Levels 1 and 0

When a TLR Level 1 or 0 is issued, the Constrained Facility is no longer under SOL or IROL violation and all Interchange Transactions are allowed to flow. In order to provide the Reliability Coordinators with a view of the Interchange Transactions that were halted or curtailed on previous TLR actions (level 2 or higher) and are now available for reloading, the IDC provides such information in the TLR report.

New Tag Alarming

Those Interchange Transactions that are at or above the Curtailment Threshold and are *not* candidates for Reallocation because the tags for those Transactions were not submitted by the approved tag submission deadline for Reallocation will be flagged as HOLD and must not be permitted to start or increase during the next hour. To alert Reliability Coordinators of those Transactions required to be held, the IDC will generate a report (for viewing within the IDC only) at various times. The report will include a list of all HOLD Transactions. In order not to overwhelm the Reliability Coordinator with alarms, only those who issued the TLR and those whose Transactions sink within their Reliability Area will be alarmed. An alarm will be issued for a given tag only once and will be issued for all TLR levels for which halting new Transactions is required: TLR Level 2, 3a, 3b, 5a and 5b.

Tag Adjustment

The Interchange Transactions with statuses of HOLD, CURTAILED or PROCEED must be adjusted by a Tag Authority or Tag Approval entity. Without the tag adjustments, the IDC will assume that Interchange Transactions were not curtailed/held and are flowing at their specified schedule amounts.

1. Interchange Transactions marked as CURTAILED should be adjusted to a cap equal to, or at the request of the originating PSE, less than the reallocated amount (shown as the MW CAP on the IDC report). This amount may be zero if the Transaction is fully curtailed.
2. Interchange Transaction marked as PROCEED should be adjusted to reload (NULL or to its MW level in accordance with its Energy Profile in the adjusted MW in the E-Tag) if the Interchange Transaction has been previously adjusted; otherwise, if the Interchange Transaction is flowing in full, the Tag Authority need not issue an adjust.
3. Interchange Transactions marked as HOLD should be adjusted to 0 MW.

Special Tag Status

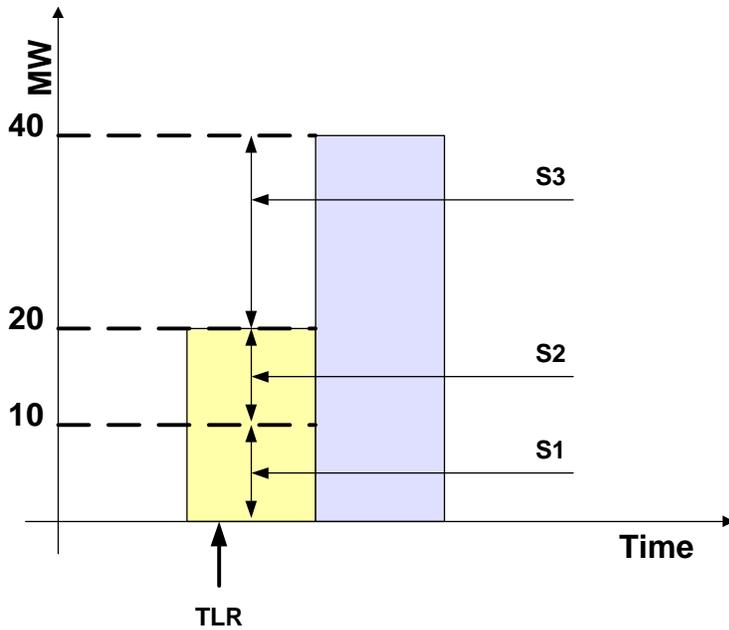
There are cases in which a tag may be marked with a composite state of ATTN_REQD to indicate that tag Authority/Approval failed to communicate or there is an inconsistency between the validation software of different tag Authority/Approval entities. In this situation, the tag is no longer subject to passive approval and its status change to IMPLEMENT may take longer than 10 minutes. Under these circumstances, the IDC may have a tag that is issued prior to the Tag Submittal Deadline that will not be a candidate for Reallocation. Such tags, when approved by the Tag Authority, will be marked as HOLD and must be halted.

Transaction Sub-Priority Examples

The following describes examples of Interchange Transactions using Non-firm Transmission Service sub-priority setting for a Interchange Transaction under different circumstances of current-hour and next-hour schedules and active MW flowing as modified by tag adjust table in E-Tag.

Example 1 – Transaction curtailed, next-hour Energy Profile is higher

Energy Profile: Current hour	20 MW
Actual flow following curtailment: Current hour	10 MW
Energy Profile: Next hour	40 MW

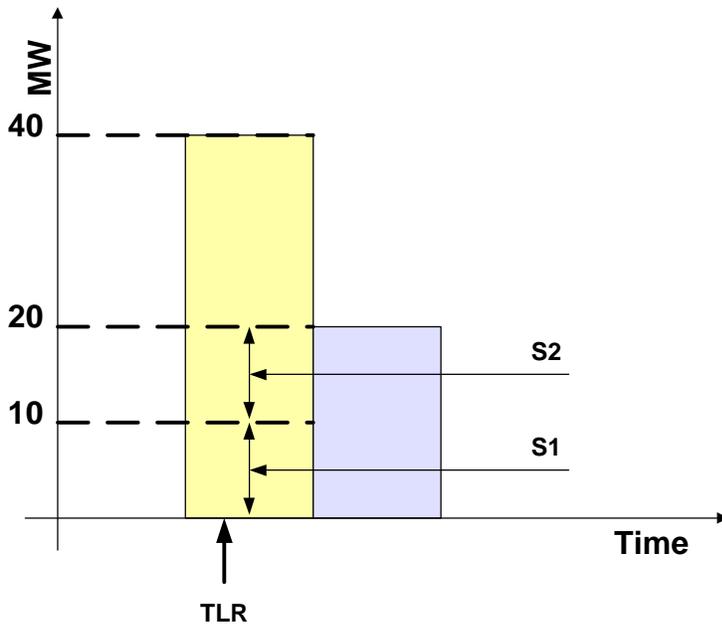


Sub-priorities for Transaction MW:

<i>Sub-Priority</i>	<i>MW Value</i>	<i>Explanation</i>
S1	10 MW	Maintain current curtailed flow
S2	+10 MW	Reload to current hour Energy Profile
S3	+20 MW	Load to next hour Energy Profile
S4		

Example 2 – Transaction curtailed, next-hour Energy Profile is lower

Energy Profile: Current hour	40 MW
Actual flow following curtailment: Current hour	10 MW
Energy Profile: Next hour	20 MW

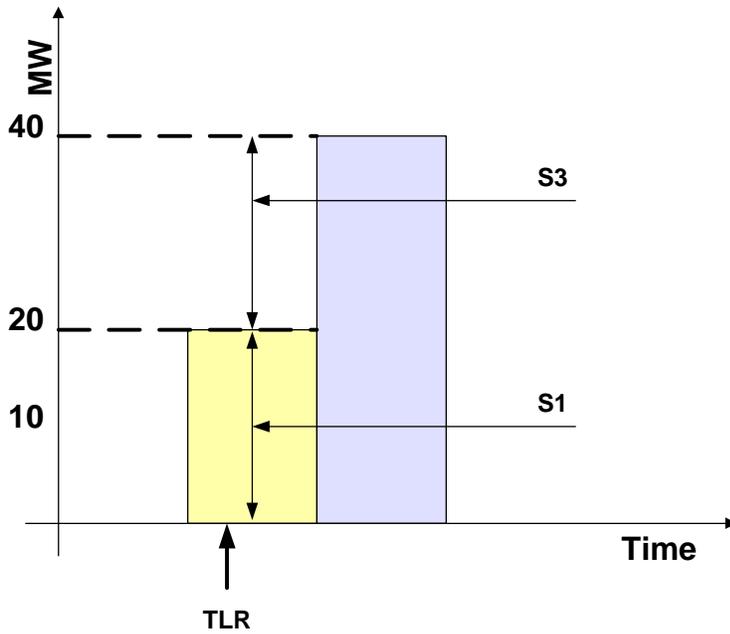


Sub-priorities for Transaction MW:

<i>Sub-Priority</i>	<i>MW Value</i>	<i>Explanation</i>
S1	10 MW	Maintain current curtailed flow
S2	+10 MW	Reload to <i>lesser</i> of current and next-hour Energy Profile
S3	+0 MW	Next-hour Energy Profile is 20MW, so no change in MW value
S4		

Example 3 – Transaction not curtailed, next-hour Energy Profile is higher

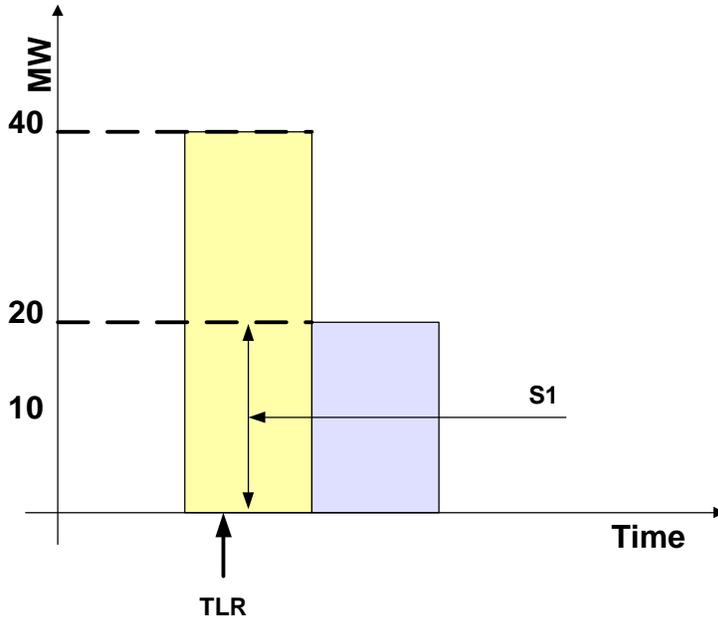
Energy Profile: Current hour	20 MW
Actual flow following curtailment: Current hour	20 MW (no curtailment)
Energy Profile: Next hour	40 MW



<i>Sub-Priority</i>	<i>MW Value</i>	<i>Explanation</i>
S1	20 MW	Maintain current flow (not curtailed)
S2	+0 MW	Reload to <i>lesser</i> of current and next-hour Energy Profile
S3	+20 MW	Next-hour Energy Profile is 40MW
S4		

Example 4 – Transaction not curtailed, next-hour Energy Profile is lower

Energy Profile: Current hour	40 MW
Actual flow following curtailment: Current hour	40 MW (no curtailment)
Energy Profile: Next hour	20 MW

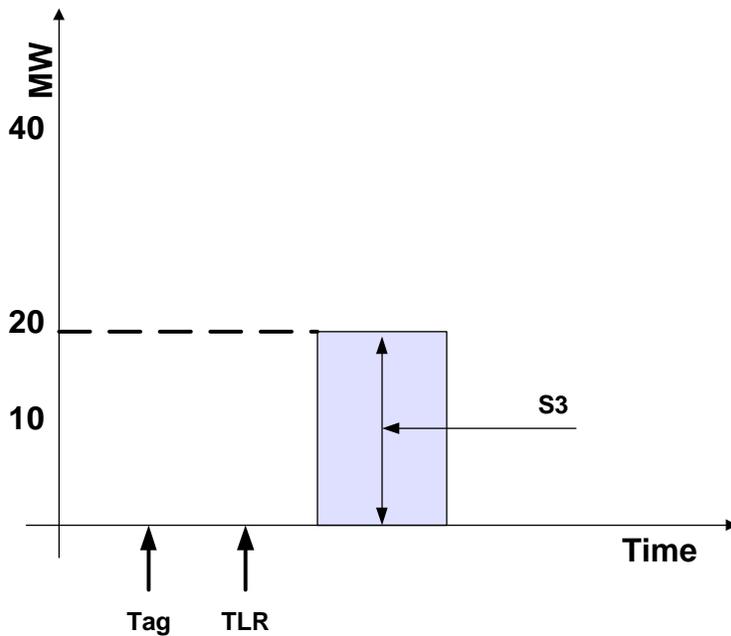


Sub-priorities for Transaction MW:

<i>Sub-Priority</i>	<i>MW Value</i>	<i>Explanation</i>
S1	20 MW	Reduce flow to next-hour Energy Profile (20MW)
S2	+0 MW	Reload to <i>lesser</i> of current and next-hour Energy Profile
S3	+0 MW	Next-hour Energy Profile is 20MW
S4		

Example 5 — TLR Issued before Transaction was scheduled to start

Energy Profile: Current hour	0 MW
Actual flow following curtailment: Current hour	0 MW (Transaction scheduled to start <i>after</i> TLR initiated)
Energy Profile: Next hour	20 MW



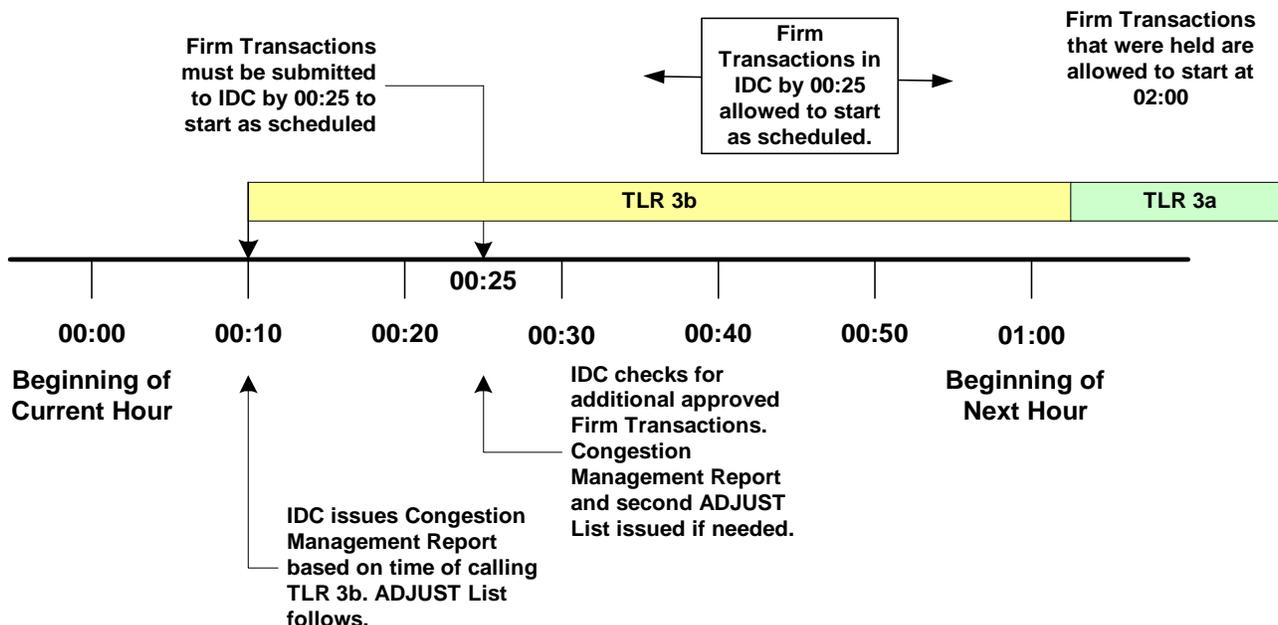
<i>Sub-Priority</i>	<i>MW Value</i>	<i>Explanation</i>
S1	0 MW	Transaction was not allowed to start
S2	+0 MW	Transaction was not allowed to start
S3	+20 MW	Next-hour Energy Profile is 20MW
S4	+0	Tag submitted prior to TLR

Appendix F. Considerations for Interchange Transactions

Using Firm Point-to-Point Transmission Service

The following cases explain the circumstances under which an Interchange Transaction using Firm Point-to-Point Transmission Service will be allowed to start as scheduled during a TLR 3b:

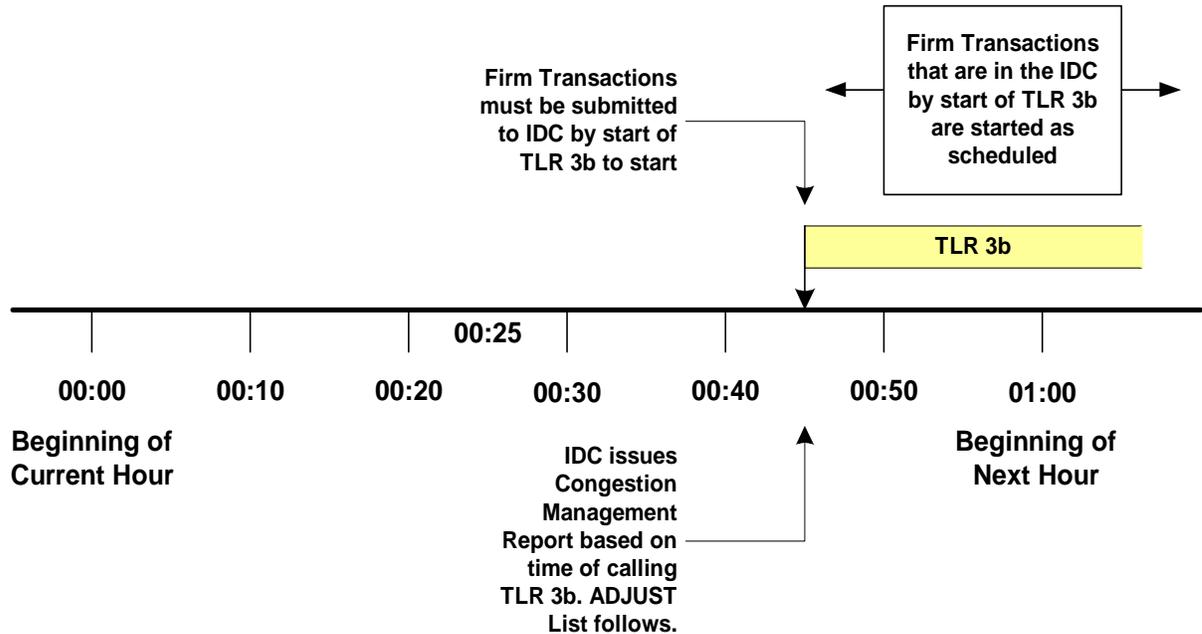
Case 1: TLR 3b is called between 00:00 and 00:25 and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to IDC by 00:25.



1. The IDC will examine the current hour (00) and next hour (01) for all Interchange Transactions.
2. The IDC will issue an ADJUST List based upon the time the TLR 3b is called. The ADJUST List will include curtailments of Interchange Transactions using Non-firm Point-to-Point Transmission Service as necessary to allow room for those Interchange Transactions using Firm Point-to-Point Transmission Service to start as scheduled.
3. At 00:25, the IDC will check for additional Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by that time and issue a second ADJUST List if those additional Interchange Transactions are found.
4. All existing or new Interchange Transactions using Non-firm Point-to-Point Transmission Service that are increasing or expected to start during the current hour or next hour will be placed on HALT or HOLD. There is no Reallocation of lower-priority Interchange Transactions using Non-firm Point-to-Point Transmission Service.
5. Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by 00:25 will be allowed to start as scheduled.
6. Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC after 00:25 will be held.

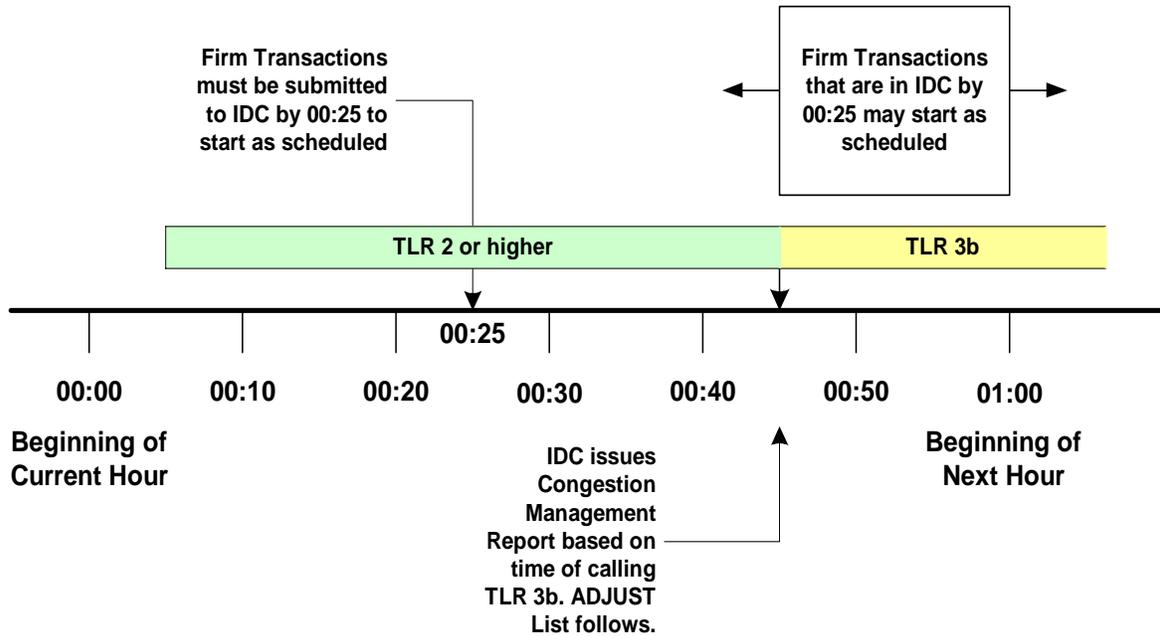
7. Once the SOL or IROL violation is mitigated, the Reliability Coordinator shall call a TLR Level 3a (or lower). If a TLR Level 3a is called:
 - a. Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by 00:25 will be allowed to start as scheduled at 02:00.
 - b. Interchange Transactions using Non-firm Point-to-Point Transmission Service that were held may then be reallocated to start at 02:00.

Case 2: TLR 3b is called after 00:25 and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to the IDC no later than the time at which the TLR 3b is called.



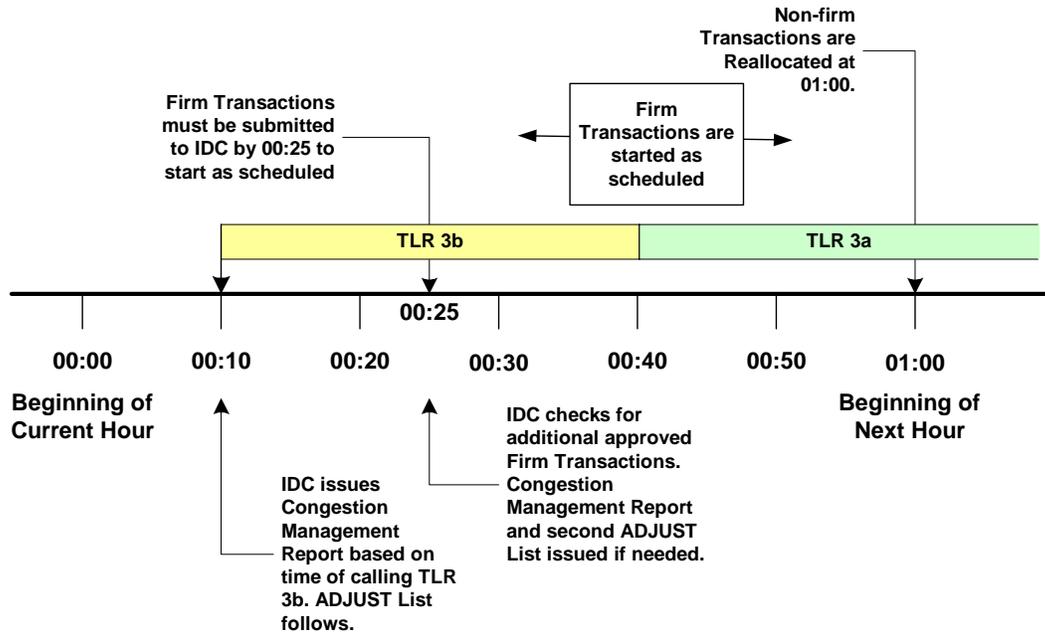
1. The IDC will examine the current hour (00) and next hour (01) for all Interchange Transactions.
2. The IDC will issue an ADJUST List at the time the TLR 3b is called. The ADJUST List will include additional curtailments of Interchange Transactions using Non-firm Point-to-Point Transmission Service as necessary to allow room for those Interchange Transactions using Firm Point-to-Point Transmission Service to start at as scheduled.
3. All existing or new Interchange Transactions using Non-firm Point-to-Point Transmission Service that are increasing or expected to start during the current hour or next hour will be placed on HALT or HOLD. There is no Reallocation of lower-priority Interchange Transactions using Non-firm Point-to-Point Transmission Service.
4. Interchange Transactions using Firm Point-to-Point Transmission Service that were submitted to the IDC by the time the TLR 3b was called will be allowed to start at as scheduled.
5. Interchange Transaction using Firm Point-to-Point Transmission Service that were submitted to the IDC after the TLR 3b was called will be held until the next issuance for TLR (either TLR 3b, 3a, or lower level).

Case 3. TLR 2 or higher is in effect, a TLR 3b is called after 00:25, and the Interchange Transaction using Firm Point-to-Point Transmission Service is submitted to the IDC by 00:25.



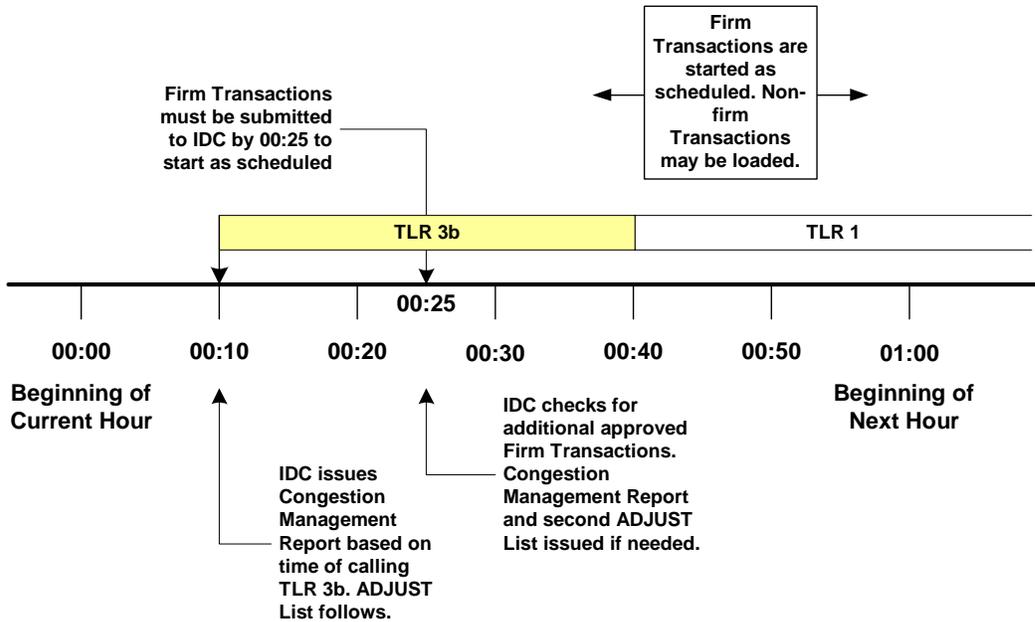
If a TLR 2 or higher has been issued and 3B is subsequently issued, then only those Interchange Transactions using Firm Point-to-Point Transmission Service that had been submitted to the IDC by 00:25 will be allowed to start as scheduled. All other Interchange Transactions are held.

Case 4. TLR 3b is called before 00:25 and the Interchange Transaction is submitted to the IDC by 00:25. TLR 3a is called at 00:40.



1. Same as Case 1, but TLR Level 3b ends at 00:40 and becomes TLR Level 3a.
2. All Interchange Transactions using Firm Point-to-Point Transmission Service will start as scheduled if in by the time the 3A is declared.
3. All Interchange Transactions using Non-firm Point-to-Point Transmission Service are reallocated at 01:00.

Case 5. TLR 3b is called before 00:25 and the Interchange Transaction is submitted to the IDC by 00:25. TLR 1 is called at 00:40.



1. Same as Case 1, but TLR Level 3b ends at 00:40 and becomes TLR Level 1.
2. All Interchange Transactions using Firm Point-to-Point Transmission Service will start as scheduled.
3. All Interchange Transactions using Non-firm Point-to-Point Transmission Service may be loaded immediately.

Appendix G. Examples of On-Path and Off-Path Mitigation

Examples

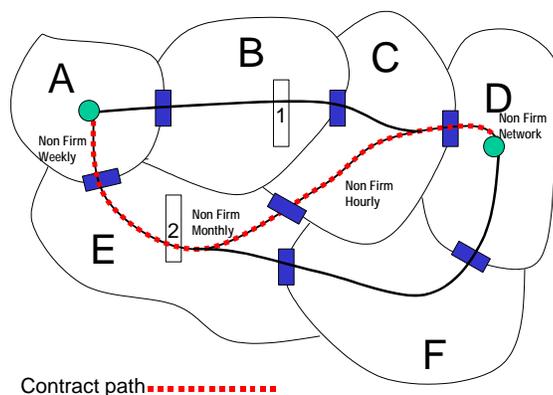
This section explains, by example, the obligations of the Transmission Service Providers on and off the Contract Path when calling for Transmission Loading Relief. (References to Principles refer to Requirement 4, “Mitigating Constraints On and Off the Contract Path during TLR,” on the preceding pages.) When Reallocating or curtailing Interchange Transactions using Firm Point-to-Point Transmission Service under TLR Level 5a or 5b, the Transmission Service Providers may be obligated to perform comparable curtailments of its Transmission Service to Network Integration and Native Load customers. See Requirement 5, “Parallel Flow Calculation Procedure for Reallocating or Curtailing Firm Transmission Service during TLR.”

Scenario:

- Interchange Transaction arranged from system A to system D, and assumed to be at or above the Curtailment Threshold.
- Contract path is A-E-C-D (except as noted).
- Locations 1 and 2 denote Constraints.

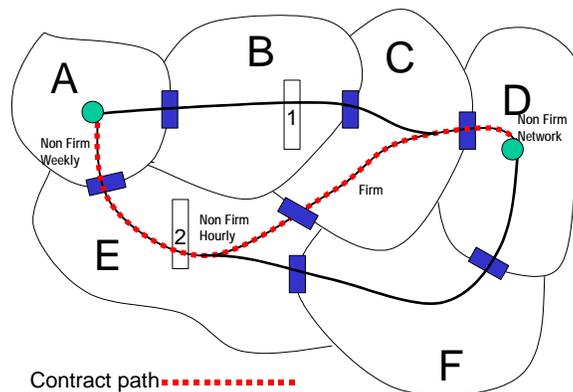
Case 1: E is a non-firm Monthly path; C is non-firm Hourly; E has Constraint at #2

- E may call its Reliability Coordinator for TLR to relieve overload at Constraint #2.
- Interchange Transaction A-D may be curtailed by TLR action as though it was being served by Non-firm Monthly Point-to-Point Transmission Service, even though it was using Non-firm Hourly Point-to-Point Transmission Service from C. That is, it takes on the priority of the link with the Constrained Facility along the Contract Path (Principle 1).



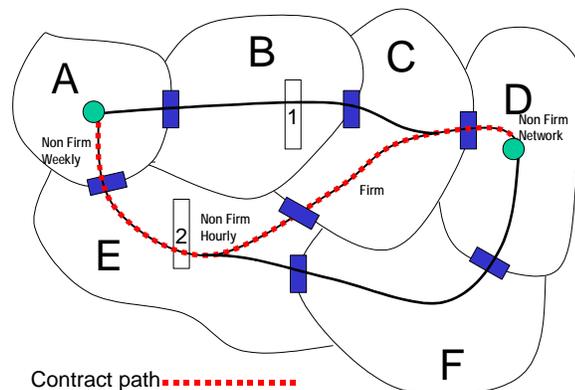
Case 2: E is a non-firm hourly path, C is firm; E has Constraint at #2

- Although C is providing Firm Service, the Constraint is not on C’s system; therefore E is not obligated to treat the Interchange Transaction as though it was being served by Firm Point-to-Point Transmission Service.
- E may call its Reliability Coordinator for TLR to relieve overload at Constraint #2.
- Interchange Transaction A-D may be curtailed by TLR action as though it was being served by Non-firm Hourly Point-to-Point Transmission Service, even though it was using firm service from C. That is, when the constraint is on the Contract Path, the Interchange Transaction takes on the priority of the link with the Constrained Facility (Principle 1).



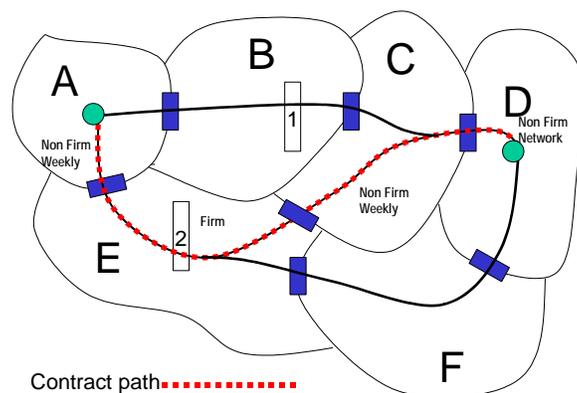
Case 3: E is a non-firm hourly path, C is firm, B has Constraint at #1

- B may call its Reliability Coordinator for TLR to relieve overload at Constraint #1.
- Interchange Transaction A-D may be curtailed by TLR action as though it was being served by Non-firm Hourly Transmission Service, even if it was using firm Transmission Service elsewhere on the path. When the constraint is off the Contract Path, the Interchange Transaction takes on the lowest priority reserved on the Contract Path (Principle 3).



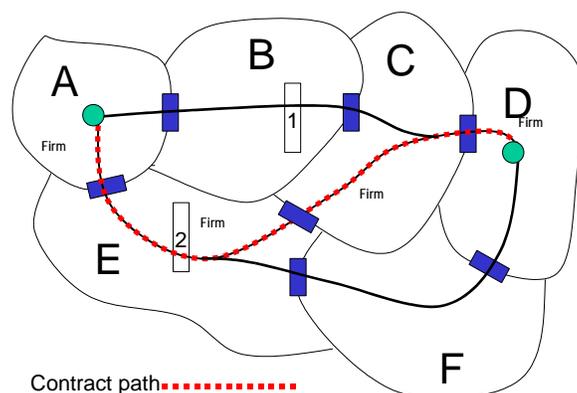
Case 4: E is a firm path; A, D, and C are Non-firm; E has Constraint at #2

- Interchange Transaction A – D is considered Firm priority for curtailment purposes.
- E may then call its Reliability Coordinator for TLR, which would curtail all Interchange Transactions using Non-firm Point-to-Point Transmission Service first.
- E is obligated to try to reconfigure transmission to mitigate Constraint #2 in E before E may curtail the Interchange Transaction as ordered by the TLR (Principle 2).



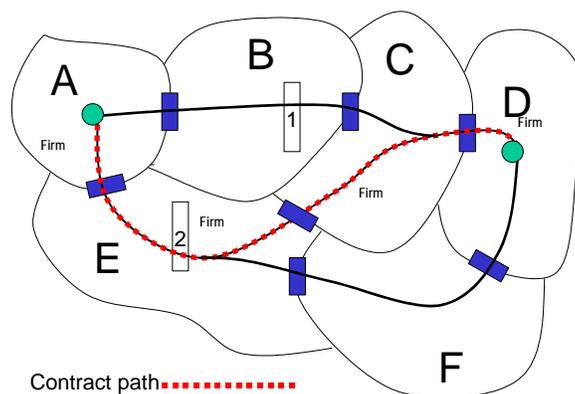
Case 5: The entire path (A-E-C-D) is firm; E has Constraint at #2

- Interchange Transaction A – D is considered Firm priority for curtailment purposes.
- E may call its Reliability Coordinator for TLR, which would curtail all Interchange Transactions using Non-firm Point-to-Point Transmission Service first.
- E is obligated to curtail Interchange Transactions using Non-firm Point-to-Point Transmission Service, and then reconfigure transmission on its system, or, if there is an agreement in place, arrange for reconfiguration or other congestion management options on another system, to mitigate Constraint #2 in E before the firm A-D transaction is curtailed (Principle 2).
- A, C, D, may be requested by E to try to reconfigure transmission to mitigate Constraint #2 in E at E's expense (Principle 2).



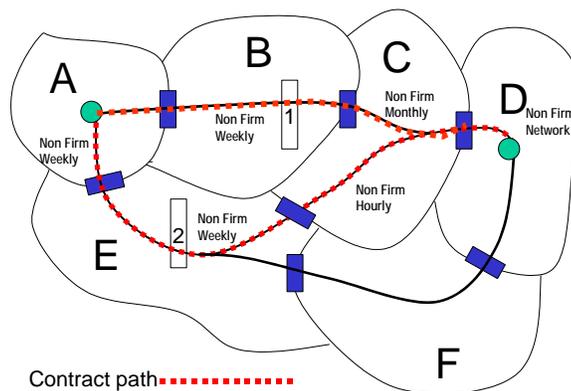
Case 6: The entire path (A-E-C-D) is firm; B has Constraint at #1.

- Interchange Transaction A – D is considered Firm priority for curtailment purposes.
- B may call its Reliability Coordinator for TLR for all *non-firm* Interchange Transactions that contribute to the overload at Constraint #1.
- Following the curtailment of all non-firm Interchange Transactions, the Reliability Coordinator (ies) will determine which Transmission Operator(s) will reconfigure their transmission, if possible, to mitigate constraint #1 (Principle 4).
- A-D transaction may be curtailed as a result. However, the A-D transaction is treated as a firm Interchange Transaction and will be curtailed only after non-firm Interchange Transactions. (Note: This means that the firm Contract Path is respected by all parties, including those not on the Contract Path.) (Principle 4)



Case 7: Two A-to-D transactions using A-B-C-D and A-E-C-D; A and B are non-firm; B has Constraint at #1

- B is not obligated to reconfigure transmission to mitigate Constraint at #1. (Principle 1)
- B may call its Reliability Coordinator for TLR to relieve overload at Constraint #1.
- If both A – D Interchange Transactions have the same Transfer Distribution Factors across Constraint #1, then they both are subject to curtailment. However, Interchange Transaction A – D using the A-B-C-D path is assigned a higher priority (priority NW on B), and would not be curtailed until after the Interchange Transaction using the path A-E-C-D (priority NH on the Contract Path as observed by B who is off the Contract Path).



Standard Development Roadmap

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed:

1. SAC approves Version 0 SAR for posting (April 14, 2004).
2. SAC approves *Plan for Accelerating Adoption of NERC Reliability Standards* (April 19, 2004).
3. Board approves *Plan for Accelerating Adoption of NERC Reliability Standards* (June 15, 2004).
4. SAC appoints Version 0 Drafting Team (May 7, 2004).
5. SAC approves development of Version 0 standards (June 23, 2004).
6. Drafting Team posts Draft 1 for comment (July 9 to August 9, 2004).
7. JIC assigns Version 0 reliability standards to NERC and business practices to NAESB (August 16, 2004).
8. Drafting Team posts Draft 2 for comment (September 1 to October 15, 2004).

Description of Current Draft:

Draft 3 is to be posted for a 30-day posting prior to balloting the Version 0 standards. This draft includes revisions based on industry comments received during the posting of Draft 2. Changes from Draft 2 are highlighted in the redline copy of Draft 3.

Future Development Plan:

Anticipated Actions

Anticipated Date

- | | |
|---|--|
| 1. Seek endorsement of NERC technical committees. | November 9–11, 2004 |
| 2. First ballot of Version 0 standards. | December 1–10, 2004 |
| 3. Recirculation ballot of Version 0 standards. | December 27, 2004 –
January 7, 2005 |
| 4. 30-day posting before board adoption. | January 8, 2005 –
February 8, 2005 |
| 5. Board adopts Version 0 standards. | February 8, 2005 |
| 6. Effective date. | April 1, 2005 |

A. Introduction

- 1. Title:** Reliability Coordination – System Restoration
- 2. Number:** EOP-006-0
- 3. Purpose:** The Reliability Coordinator must have a coordinating role in system restoration to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection.
- 4. Applicability**
 - 4.1.** Reliability Coordinator.
- 5. Proposed Effective Date:** April 1, 2005

B. Requirements

- R1.** Each Reliability Coordinator shall be aware of the restoration plan of each Transmission Operator in its Reliability Coordinator Area in accordance with NERC and regional requirements.
- R2.** The Reliability Coordinator shall monitor restoration progress and coordinate any needed assistance.
- R3.** The Reliability Coordinator shall have a Reliability Coordinator Area restoration plan that provides coordination between individual Transmission Operator restoration plans and that ensures reliability is maintained during system restoration events.
- R4.** The Reliability Coordinator shall serve as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators and Transmission Operators or Balancing Authorities not immediately involved in restoration.
- R5.** Reliability Coordinators shall approve, communicate, and coordinate the re-synchronizing of major system islands or synchronizing points so as not to cause a Burden on adjacent Transmission Operator, Balancing Authority, or Reliability Coordinator Areas.
- R6.** The Reliability Coordinator shall take actions to restore normal operations once an operating emergency has been mitigated in accordance with its restoration plan.

C. Measures

Not specified.

D. Compliance

Not specified.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
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