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 SAR for posting on January 9, 2006.
2. The SAR was posted for comment from January 16, 2006 to February 15 2006.
3. The SAC approves development of the standard on May 12, 2006.
4. The JIC assigns development of the standard to NERC on June 15, 2006.
5. Drafting team posts first draft for comments (August 16–September 29, 2006).
6. Drafting team posts second draft with implementation plan for comments (January 9–February 7, 2007).
7. Drafting team posts third draft for comments (March 19–April 17, 2007)

Description of Current Draft:

This drafting team did not make any technical changes to the standard based on comments received during the third posting. The compliance staff has not recommended field testing the compliance elements of this standard. The drafting team will ask the Standards Committee for authorization to post the standard and implementation plan for a 30-day, pre-ballot review.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for 30-day, pre-ballot period.	October 12–November 10, 2007
2. First ballot of standards.	November 12–21, 2007
3. Recirculation ballot of standards.	December 4–13, 2007
4. Board adopts standards.	To be determined

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

None.

A. Introduction

1. Title: Transmission Relay Loadability

2. Number: PRC-023-1

3. Purpose: Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.

4. Applicability:

4.1. Transmission Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined below:

4.1.1 Transmission lines operated at 200 kV and above.

4.1.2 Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

4.1.3 Transformers with low voltage terminals connected at 200 kV and above.

4.1.4 Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.

4.2. Generator Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined in 4.1.1 through 4.1.4.

4.3. Distribution Providers with load-responsive phase protection systems as described in Attachment A, applied according to facilities defined in 4.1.1 through 4.1.4., provided that those facilities have bi-directional flow capabilities.

4.4. Planning Coordinators.

5. Effective Dates[1]:

5.1. Requirement 1, Requirement 2~~, Requirement 4~~:

5.1.1 For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later; or, in those jurisdictions where no regulatory approval is required, the first calendar quarter following Board of Trustee adoption.

5.1.2 For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals or, in those jurisdictions where no regulatory approval is required, the first calendar quarter 39 months following Board of Trustee adoption.

1 Temporary Exceptions that have already been approved by the NERC Planning Committee via the NERC System Protection and Control Task Force prior to the approval of this standard shall not result in either findings of non-compliance or sanctions if all of the following apply: (1) the approved requests for Temporary Exceptions include a mitigation plan (including schedule) to come into full compliance, and (2) the non-conforming relay settings are mitigated according to the approved mitigation plan.

~~5.1.2 .~~

~~Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its Planning Coordinator pursuant to R3.3 to comply with R1 (including all sub-requirements) for each facility that is added to the Planning Coordinator's critical facilities list determined pursuant to R3.1.~~

5.2. Requirement 3: First calendar quarter 18 months following applicable regulatory approvals; or, in those jurisdictions where no regulatory approval is required, first calendar quarter 18 months following Board of Trustee adoption.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. Relay settings for critical facilities added to the critical facility list pursuant to requirement R3.3 shall be set within 24 months of receipt of the notice from the Planning Coordinator. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees: [Violation Risk Factor: High] [Mitigation Time Horizon: Long Term Planning].

R1.1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes).

R1.2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[2] of a circuit (expressed in amperes).

R1.3. Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation:

R1.3.1. An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.

R1.3.2. An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

R1.4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

- 115% of the highest emergency rating of the series capacitor.
- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with R1.3, using the full line inductive reactance.

[2] When a 15-minute rating has been calculated and published for use in real-time operations, the 15-minute rating can be used to establish the loadability requirement for the protective relays.

R1.5. Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes).

R1.6. Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability.

R1.7. Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration.

R1.8. Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration.

R1.9. Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration.

R1.10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at or below the greater of:

- 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment.
- 115% of the highest operator established emergency transformer rating.

R1.11. For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following:

- Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload.
- Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100° C for the top oil or 140° C for the winding hot spot temperature[3].

R1.12. When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints:

R1.12.1. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

R1.12.2. Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees.

[3] IEEE standard C57.115, Table 3, specifies that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and cautions that bubble formation may occur above 140 degrees C.

R1.12.3. Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit.

R1.13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

R2. The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R3. The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R3.1. The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System.

R3.1.1. This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.

R3.2. The Planning Coordinator shall maintain a current list of facilities determined according to the process described in R3.1.

R3.3. The Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list.

~~**R4.**Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its Planning Coordinator pursuant to R3.3 to comply with R1 (including all sub-requirements) for each facility that is added to the Planning Coordinator's critical facilities list determined pursuant to R3.1. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]~~

C. Measures

M1. The Transmission Owner, Generator Owner, and Distribution Provider shall each have evidence to show that its transmission relays are set according to one of the criteria in R1.1 through R1.13. (R1~~) and R4~~)

M2. The Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to the criteria in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 shall have evidence that the resulting Facility Rating was agreed to by its associated Planning Authority, Transmission Operator, and Reliability Coordinator. (R2)

M3. The Planning Coordinator shall have a documented process for the determination of facilities as described in R3. The Planning Coordinator shall have a current list of such facilities and shall have evidence that it provided the list to the approriate Reliability Coordinators, Transmission Operators, Generator Operators, and Distribution Providers. (R3)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance ~~Monitoring Responsibility~~Enforcement Authority

~~1.1.1Regional Entity.~~

1.1.1 ~~Compliance Enforcement Authority~~Regional Entity for all responsible entities except those responsible entities that work for the Regional Entity

1.1.2 ERO for all responsible entities that work for the Regional Entity

1.2. ~~Compliance Monitoring Period and~~Violation Reset Time ~~Frame~~Period

One calendar year.

1.3. Data Retention

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation for three years.

The Planning Coordinator shall retain documentation of the most recent review process required in R3. The Planning Coordinator shall retain the most recent list of facilities that are critical to the reliability of the electric system determined per R3.

The Compliance Monitor shall retain its compliance documentation for three years.

1.4. Additional Compliance Information

The Transmission Owner, Generator Owner, Planning Coordinator, and Distribution Provider shall each demonstrate compliance through annual self-certification ~~or~~, compliance audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance ~~Monitor~~Enforcement Authority.

2. Violation Severity Levels (R1, R2): Transmission Owner, Generator Owner, and Distribution Provider

2.1. Lower: Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2.

2.2. Moderate: Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but is incomplete or incorrect for one or more of the requirements.

2.3. High: NA

2.4. Severe: There shall be a severe violation severity level if either of the following conditions exist:

2.4.1 Relay settings do not comply with any of the requirements in R1.1 ~~thought~~through R1.13

2.4.2 Evidence does not exist to support that relay settings comply with one of the criteria in R1.1 through R1.13.

3. Violation Severity Levels (R3): Planning Coordinator

3.1. Lower: N/A

3.2. Moderate: Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 31 days and 45 days after the list was established or updated.

3.3. High: Provided the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers between 46 days and 60 days after list was established or updated.

3.4. Severe: There shall be a severe violation severity level if any of the following conditions exist:

3.4.1 Does not have a process in place to determine facilities that are critical to the reliability of the Bulk Electric System.

3.4.2 Does not maintain a current list of facilities critical to the reliability of the Bulk Electric System,

3.4.3 Did not provide the list of facilities critical to the reliability of the Bulk Electric System to the appropriate Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers, or provided the list more then 60 days after the list was established or updated.

E. Regional Differences

None

~~F.Associated Documents~~

F. Supplemental Technical Reference Document

~~The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies~~

"Determination and Application of Practical Relaying Loadability Ratings," Version 1.0, January 9, 2007, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/~filez/reports.html.

Version History

Version	Date	Action	Change Tracking

Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

- **1.1.** Phase distance.
- **1.2.** Out-of-step tripping.
- **1.3.** Switch-on-to-fault.
- **1.4.** Overcurrent relays.
- **1.5.** Communications aided protection schemes including but not limited to:
  - **1.5.1** Permissive overreach transfer trip (POTT).
  - **1.5.2** Permissive under-reach transfer trip (PUTT).
  - **1.5.3** Directional comparison blocking (DCB).
  - **1.5.4** Directional comparison unblocking (DCUB).

2. This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.

3. The following protection systems are excluded from requirements of this standard:

- **3.1.** Relay elements that are only enabled when other relays or associated systems fail. For example:
  - Overcurrent elements that are only enabled during loss of potential conditions.
  - Elements that are only enabled during a loss of communications.
- **3.2.** Protection systems intended for the detection of ground fault conditions.
- **3.3.** Protection systems intended for protection during stable power swings.
- **3.4.** Generator protection relays that are susceptible to load.
- **3.5.** Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.
- **3.6.** Protection systems that are designed only to respond in time periods which allow operators 15 minutes or greater to respond to overload conditions.
- **3.7.** Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
- **3.8.** Relay elements associated with DC lines.
- **3.9.** Relay elements associated with DC converter transformers.