Standard Development Timeline

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. SAR posted for comment from August 19, 2010 through September 19, 2010.
2. SC authorized moving the SAR forward to standard development on August 12, 2010.
3. SC authorized initial posting of draft 1 on April 24, 2014.
4. Draft 1 of PRC-026-1 was posted for a 45-day formal comment period from April 25 – June 9, 2014 and an initial ballot in the last ten days of the comment period from May 30 – June 9, 2014.

Description of Current Draft

The Protection System Response to Power Swings Standard Drafting Team (PSRPS SDT) is posting Draft 2 of PRC-026-1 – Relay Performance During Stable Power Swings for a 45-day additional comment period and concurrent/parallel initial ballot in the last ten days of the comment period.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Concurrent/Parallel Initial Ballot	April 2014
45-day Formal Comment Period with Concurrent/Parallel Additional Ballot	August 2014
Final Ballot	September 2014
BOT Adoption	November 2014

Version History

Version	Date	Action	Change Tracking
1.0	TBD	Effective Date	New

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 Glossary of Terms Used in Reliability Standards 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.

Term: None.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Relay Performance During Stable Power Swings**

2. **Number:** **PRC-026-1**

3. **Purpose:** To ensure that load-responsive protective relays are not expected to trip in response to stable power swings during non-Fault conditions.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Generator Owner that applies load-responsive protective relays as described in PRC-026-1 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

   4.1.2 Planning Coordinator.

   4.1.3 Transmission Owner that applies load-responsive protective relays as described in PRC-026-1 – Attachment A at the terminals of the Elements listed in Section 4.2, Facilities.

   4.2. Facilities: The following Bulk Electric System (BES) Elements:

   4.2.1 Generators.

   4.2.2 Transformers.

   4.2.3 Transmission lines.

5. **Background:**

   This is Phase 3 of a three-phased standard development that is focused on developing a new Reliability Standard, PRC-026-1 – Relay Performance During Stable Power Swings, to address protective relay operations due to stable power swings. The March 18, 2010, FERC Order No. 733, approved Reliability Standard PRC-023-1 – Transmission Relay Loadability. In this Order, FERC directed NERC to address three areas of relay loadability that include modifications to the approved PRC-023-1, development of a new Reliability Standard to address generator protective relay loadability, and a new Reliability Standard to address the operation of protective relays due to stable power swings. This project's SAR addresses these directives with a three-phased approach to standard development.

   Phase 1 focused on making the specific modifications to PRC-023-1 and was completed in the approved Reliability Standard PRC-023-2, which became mandatory on July 1, 2012.

   Phase 2 focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability; PRC-025-1 is currently awaiting regulatory approval.

This Phase 3 of the project focuses on developing a new Reliability Standard, PRC-026-1 – Relay Performance During Stable Power Swings, to address protective relay operations due to stable power swings. This Reliability Standard will establish requirements aimed at preventing protective relays from tripping unnecessarily due to stable power swings by requiring each Transmission Owner and Generator Owner to assess the security of protective relay systems that are susceptible to operation during power swings, and take actions to improve security for stable power swings where such actions would not compromise dependable operation for faults and unstable power swings.

6. Effective Date:

First day of the first full calendar year that is twelve months beyond the date that this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the first full calendar year that is twelve months beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

B. Requirements and Measures

R1. Each Planning Coordinator shall, at least once each calendar year, identify each Element in its area that meets one or more of the following criteria and provide notification to the respective Generator Owner and Transmission Owner, if any: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Criteria:

1. Generator(s) where an angular stability constraint exists which is addressed by an operating limit or a Remedial Action Scheme (RAS) and those Elements terminating at the transmission switching station associated with the generator(s).
2. An Element that is monitored as part of a System Operating Limit (SOL) that has been established based on angular stability constraints identified in system planning or operating studies.
3. An Element that forms the boundary of an island due to angular instability within an underfrequency load shedding (UFLS) assessment.
4. An Element identified in the most recent Planning Assessment where relay tripping occurs due to a stable or unstable power swing during a simulated disturbance.
5. An Element reported by the Generator Owner or Transmission Owner pursuant to Requirement R2 or Requirement R3, unless the Planning Coordinator determines the Element is no longer susceptible to power swings.

M1. Each Planning Coordinator shall have dated evidence that demonstrates identification and the respective notification of the Element(s), if any, which meet one or more of the criteria in Requirement R1. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

Rationale for R1: The Planning Coordinator has a wide-area view and is in the position to identify Elements which meet the criteria, if any. The criterion-based approach is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document *Protection System Response to Power Swings*, August 2013, which recommends a focused approach to determine an at-risk Element.

R2. Each Transmission Owner shall, within 120 calendar days of identifying an Element that meets either of the following criteria, provide notification of the Element to its Planning Coordinator: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Criteria:

1. An Element that trips due to a stable or unstable power swing during an actual system Disturbance.
2. An Element that forms the boundary of an island during an actual system Disturbance.

M2. Each Transmission Owner shall have dated evidence that demonstrates identification of the Element(s), if any, which meet either of the criteria in Requirement R2. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

Rationale for R2: The Transmission Owner is in the position to identify the load-responsive protective relays that have tripped due to power swings, if any. The criteria is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document *Protection System Response to Power Swings*, August 2013. A time to complete a review of the relay tripping is not addressed here as other NERC Reliability Standards address the review of Protection System operations.

R3. Each Generator Owner shall, within 120 calendar days of identifying an Element that meets the following criterion, provide notification of the Element to its Planning Coordinator: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

Criterion:

1. An Element that trips due to a stable or unstable power swing during an actual system Disturbance.

M3. Each Generator Owner shall have dated evidence that demonstrates identification of the Element(s), if any, which the criterion in Requirement R3. Evidence may include, but is not limited to, the following documentation: emails, facsimiles, records, reports, transmittals, lists, or spreadsheets.

Rationale for R3: The Generator Owner is in the position to identify the load-responsive protective relays that have tripped due to power swings, if any. The criterion is consistent with the NERC System Protection and Control Subcommittee (SPCS) technical document *Protection System Response to Power Swings*, August 2013. A time to complete a review of the relay tripping is not addressed here as other NERC Reliability Standards address the review of Protection System operations.

R4. Each Generator Owner and Transmission Owner shall, within the appropriate timeframe in Part 4.1, perform one of the actions in Part 4.2 for each Element identified pursuant to Requirement R1, R2, or R3: *[Violation Risk Factor: Medium]*

4.1 Timeframes

- Within 12 calendar months of receiving notification of an Element pursuant to Requirement R1 that has not been assessed in the last three calendar years in accordance with 4.2 Actions [Time Horizon: Operations Planning]
- Within 12 calendar months of identifying an Element pursuant to Requirement R2 or R3 [Time Horizon: Operations Planning]

4.2 Actions

- Demonstrate that the existing load-responsive protective relays are not expected to trip in response to a stable power swing based on the 4.3 Criteria below.
- Demonstrate that the existing load-responsive protective relays are not expected to trip in response to a stable power swing because power swing blocking is applied.
- Develop a Corrective Action Plan (CAP) to modify the Protection System so that the load-responsive protective relays are not expected to trip in response to a stable power swing based on the 4.3 Criteria below or by applying power swing blocking.
- If none of the options above results in dependable fault detection or dependable out-of-step tripping (if out-of-step tripping is applied at the terminal of the Element):
  a. provide the technical justification for retaining the existing Protection System design and settings to the respective Planning Coordinator, Reliability Coordinator, and Transmission Planner, or
  b. provide the technical justification for modifying the Protection System design, settings, or both to the respective Planning Coordinator, Reliability Coordinator, and Transmission Planner, and develop a CAP for this modification of the Protection System.

4.3 Criteria:

(A) A distance relay impedance characteristic, used for tripping, that is completely contained within the portion of the lens characteristic formed in the impedance (R-X) plane that connects the endpoints of the total system impedance (with the parallel transfer impedance removed) bounded by varying the sending end and receiving end voltages from 0.5 to 1.0 per unit, while maintaining a constant system separation angle across the total system impedance where:

1. The system separation angle is:
   - At least 120 degrees where power swing blocking is not applied, or
   - An angle less than 120 degrees as agreed upon by the respective Planning Coordinator, Reliability Coordinator, and Transmission Planner where power swing blocking is not applied.
2. All generation is in service and all transmission Elements are in their normal operating state when calculating the system impedance.
3. Saturated (transient or sub-transient) reactance is used for all machines.

(B) The pickup of an overcurrent element used for tripping, that is above the calculated current value (with the parallel transfer impedance removed) for the conditions below:

1. The system separation angle is:
   - At least 120 degrees where power swing blocking is not applied, or
   - An angle less than 120 degrees as agreed upon by the respective Planning Coordinator, Reliability Coordinator, and Transmission Planner where power swing blocking is not applied.
2. Both the sending and receiving voltages at 1.05 per unit.
3. All generation is in service and all transmission Elements are in their normal operating state when calculating the system impedance.
4. Saturated (transient or sub-transient) reactance is used for all machines.

M4. Each Generator Owner and Transmission Owner shall have dated evidence that demonstrates one of the options was performed according to Requirement R4. Evidence may include, but is not limited to, the following documentation: apparent impedance characteristic plots, email, design drawings, facsimiles, R-X plots, software output, records, reports, transmittals, lists, settings sheets, or spreadsheets.

Rationale for R4: Performing one of the options in Requirement R4 assures that the reliability goal of this standard will be met. Part 4.1, Timeframes, provides an amount of time for the entity to perform the required activity based on circumstances. Part 4.2, Actions, lists the activities the entity is required to perform based upon The first option ensures that the Generator Owner and Transmission Owner protective relays are secure from tripping in response to stable power swings having a system separation angle of up to 120 degrees. The second option allows the Generator Owner and Transmission Owner to exclude protective relays that have power swing blocking applied. The third option allows the Generator Owner and Transmission Owner, where possible, to modify the Protection System to meet the criterion or apply power swing blocking. The fourth option allows the Generator Owner and Transmission Owner to maintain a balance between Protection System security and dependability for cases where tripping on stable power swings may be necessary to maintain the ability to trip for unstable power swings or faults. Protection System modifications may be necessary to achieve acceptable performance. A time period of once each calendar year allows time to evaluate the Protection System, develop a CAP, or obtain necessary agreement.

R5. Each Generator Owner and Transmission Owner shall implement each CAP developed pursuant to Requirement R4, and update each CAP if actions or timetables change, until all actions are complete. *[Violation Risk Factor: Medium][Time Horizon: Long-Term Planning]*

M5. The Generator Owner and Transmission Owner shall have dated evidence that demonstrates implementation of each CAP according to Requirement R5, including updates to actions or timetables. Evidence may include, but is not limited to, the following documentation: corrective action plans, maintenance records, settings sheets, project or work management program records, or work orders.

Rationale for R5: Implementation of the CAP must accomplish all identified actions to be complete to achieve the desired reliability goal. During the course of implementing a CAP, updates may be necessary for a variety of reasons such as new information, scheduling conflicts, or resource issues. Documenting changes and completion of activities provides measurable progress and confirmation of completion.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner, Planning Coordinator, Reliability Coordinator, Transmission Owner, and Transmission Planner shall keep data or evidence to show compliance as identified below unless directed by its CEA to retain specific evidence for a longer period of time as part of an investigation.

- The Planning Coordinator shall retain evidence of Requirements R1, Measures M1 for three calendar years.
- The Transmission Owner shall retain evidence of Requirement R2, Measure M2 for three calendar years.
- The Generator Owner shall retain evidence of Requirement R3, Measure M3 for three calendar years.
- The Generator Owner and Transmission Owner shall retain evidence of Requirement R5, Measure M5 for 12 calendar months following completion of each CAP.

If a Generator Owner, Planning Coordinator, or Transmission Owner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None.

Table of Compliance Elements

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning, Long-term Planning	Medium	The responsible entity identified an Element and provided notification in accordance with Requirement R1, but was less than or equal to 30 calendar days late.	The responsible entity identified an Element and provided notification in accordance with Requirement R1, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified an Element and provided notification in accordance with Requirement R1, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The responsible entity identified an Element and provided notification in accordance with Requirement R1, but was more than 90 calendar days late. OR The responsible entity failed to identify an Element or to provide notification in accordance with Requirement R1.
R2	Operations Planning, Long-term Planning	Medium	The responsible entity identified an Element in accordance with Requirement R2, but was less than or equal to 30 calendar days late.	The responsible entity identified an Element in accordance with Requirement R2, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified an Element in accordance with Requirement R2, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The responsible entity identified an Element in accordance with Requirement R2, but was more than 90 calendar days late. OR

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The responsible entity failed to identify an Element in accordance with Requirement R2.
R3	Operations Planning, Long-term Planning	Medium	The responsible entity identified an Element in accordance with Requirement R3, but was less than or equal to 30 calendar days late.	The responsible entity identified an Element in accordance with Requirement R3, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The responsible entity identified an Element in accordance with Requirement R3, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The responsible entity identified an Element in accordance with Requirement R3, but was more than 90 calendar days late. OR The responsible entity failed to identify an Element in accordance with Requirement R3.
R4	Operations Planning, Long-term Planning	Medium	The responsible entity performed one of the options in accordance with Requirement R4, but was less than or equal to 30 calendar days late.	The responsible entity performed one of the options in accordance with Requirement R4, but was more than 30 calendar days and less than or equal to 60 calendar days late.	The responsible entity performed one of the options in accordance with Requirement R4, but was more than 60 calendar days and less than or equal to 90 calendar days late.	The responsible entity performed one of the options in accordance with Requirement R4, but was more than 90 calendar days late. OR

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The responsible entity failed to perform one of the options in accordance with Requirement R4.
R5	Operations Planning, Long-term Planning	Medium	The responsible entity implemented, but failed to update a CAP, when actions or timetables changed, in accordance with Requirement R5.	N/A	N/A	The responsible entity failed to implement a CAP in accordance with Requirement R5.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

IEEE Power System Relaying Committee WG D6. *Power Swing and Out-of-Step Considerations on Transmission Lines*. July 2005.

Kundar, Prabha. *Power System Stability and Control*. 1994. Palo Alto: EPRI, McGraw Hill, Inc.

NERC System Protection and Control Subcommittee. *Protection System Response to Power Swings*. August 2013: http://www.nerc.com/comm/PC/System%20Protection%20and%20Control%20Subcommittee%20SPCS%2020/SPCS%20Power%20Swing%20Report_Final_20131015.pdf.

Reimert, Donald. *Protective Relaying for Power Generation Systems*. 2006. Boca Raton: CRC Press.

PRC-026-1 – Attachment A

This standard includes any protective functions which could trip with or without time delay, on load current (i.e., “load-responsive”), except:

- 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
- Relay elements that are intended to trip after time delays of 15 cycles or greater
- Thermal emulation relays which are used in conjunction with dynamic Facility Ratings
- Relay elements associated with dc lines
- Relay elements associated with dc converter transformers
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (e.g., in order to prevent false operation in the event of a loss of potential) provided the distance element is set in accordance with the criteria outlined in the standard
- Relay elements associated with switch-onto-fault schemes
- Reverse power relay on the generator
- Loss-of-field relay intended to trip after time delays of 15 cycles or greater
- Generator relay elements that are armed only when the generator is disconnected from the system, (e.g., non-directional overcurrent elements used in conjunction with inadvertent energization schemes, and open breaker flashover schemes)
- Current differential relay, pilot wire relay, and phase comparison relay
- Voltage-restrained or voltage-controlled overcurrent relays.

Guidelines and Technical Basis

Currently being rewritten