UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

North American Electric Reliability Corporation	))	**Docket No. RM13-19-000**

SUPPLEMENTAL IINFORMATION TO THE PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARD PRC-025-1 (GENERATOR RELAY LOADABILITY)

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December 17, 2013

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] hereby submits proposed Reliability Standard PRC-023-3—Transmission Relay Loadability for Commission as a supplement to the petition for approval of proposed Reliability Standard PRC-025-1—Generator Relay Loadability. NERC requests that the Commission approve proposed Reliability Standard PRC-023-3 (**Exhibit A**) concurrently with proposed Reliability Standard PRC-025-1 and find that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.[4] NERC also requests approval of the associated implementation plan (**Exhibit B**) and retirement of the currently effective Reliability Standard PRC-023-2, as detailed in this supplement.

As noted in the petition, during the development of proposed Reliability Standard PRC-025-1, clarifying changes to Reliability Standard PRC-023-2 were identified by the standard drafting team as necessary to establish a bright-line distinction between the applicability of load-

1 16 U.S.C. § 824o (2006).

2 18 C.F.R. § 39.5 (2013).

3 The Commission certified NERC as the electric reliability organization ("ERO") in accordance with Section 215 of the FPA on July 20, 2006. *N. Am. Elec. Reliability Corp.*, 116 FERC ¶ 61,062 (2006).

4 Unless otherwise designated, all capitalized terms shall have the meaning set forth in the *Glossary of Terms Used in NERC Reliability Standards*, *available at* http://www.nerc.com/files/Glossary_of_Terms.pdf

responsive protective relays in the transmission and generator relay loadability Reliability Standards. As a result, a supplemental Standard Authorization Request was approved by the Standards Committee at its January 16-17, 2013 meeting to authorize the standard drafting team to make the corresponding changes.

In the previously filed PRC-025-1 petition, NERC requested the Commission delay its approval of proposed Reliability Standard PRC-025-1 until proposed Reliability Standard PRC-023-3 – Transmission Relay Loadability was submitted in a supplemental filing to the Commission. Proposed PRC-023-3 was approved by the NERC Board of Trustees at its November 7, 2013 meeting and is submitted here as a supplement to the pending petition for approval of proposed Reliability Standard PRC-025-1. To preserve consistency between proposed Reliability Standards PRC-025 and PRC-023, NERC has requested the Commission take concurrent action on the proposed Reliability Standards PRC-025-1 and PRC-023-3.

As required by Section 39.5(a)[5] of the Commission's regulations, this supplement presents the technical basis and purpose of proposed Reliability Standard PRC-023-3, a summary of the development history (**Exhibit D**), and a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672[6] (**Exhibit C**).

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5 18 C.F.R. § 39.5(a) (2013).

6 The Commission specified in Order No. 672 certain general factors it would consider when assessing whether a particular Reliability Standard is just and reasonable. *See Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, at P 262, 321-37, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

I. NOTICES AND COMMUNICATIONS

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

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II. JUSTIFICATION FOR APPROVAL

As discussed in detail in **Exhibit C**, proposed Reliability Standard PRC-023-3 satisfies the Commission's criteria in Order No. 672 and is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

A. Improvements Reflected in proposed Reliability Standard PRC-023-3

During the development of proposed Reliability Standard PRC-025-1, the standard drafting team and industry stakeholders identified the potential for compliance overlap between Reliability Standard PRC-023-2 and proposed Reliability Standard PRC-025-1. The concern was that the two Reliability Standards would overlap with regard to the application of load-

[7] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2013), to allow the inclusion of more than two persons on the service list in this proceeding.

responsive protective relays on transmission lines that connect the generating plant or generating units to the Transmission System. Proposed Reliability Standard PRC-025-1 introduces criteria for relays applied at the terminals of such lines. Requirement R1, Criterion 6 of Reliability Standard PRC-023-2, however, requires entities to "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 aggregated generation nameplate capability." The potential compliance overlap could result in a finding of a non-compliance with both Reliability Standards unless appropriate clarifying revisions are made.

To properly align proposed Reliability Standard PRC-025-1, the standard drafting team undertook an effort to revise Reliability Standard PRC-023-2. Following is an explanation of the revisions included in proposed Reliability Standard PRC-023-3.

Requirement R1, Criterion 6 of Reliability Standard PRC-023-2 was removed and the applicability section was revised to exclude "Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a Bulk Electric System generating unit or generating plant." These changes avoid overlap with the Requirements in proposed Reliability Standard PRC-025-1 that apply to these Facilities.

Proposed Reliability Standard PRC-025-1 was developed to include relay loadability requirements for all load responsive protective relays applied at the terminals of generators and GSU transformers. As such, section 2.4 of Attachment A of Reliability Standard PRC-023-2—which addressed applicability to generator protection relays—was removed in proposed Reliability Standard PRC-023-3 to avoid overlap between the two proposed Reliability Standards.

The applicability sections for the two proposed Reliability Standards are based on the location where the relays are applied and are independent of the intended protection function. Basing applicability on the physical location where the relay is applied provides the following advantages:

(i) Facilitates the establishment of generator relay loadability requirements based on the physics associated with increased generator output during stressed system conditions.

(ii) Avoids ambiguity as to whether the intended protection function is for the generating unit or the Transmission System. For example, a relay may be applied at the terminals of a generator to provide backup protection for the GSU transformer, but because the relay setting must "over-reach" the GSU transformer terminals, the relay inherently provides backup protection for the high-voltage bus and close-in portions of transmission lines.

(iii) Provides clear division of applicability between the Generator and Transmission Relay Loadability Reliability Standards based on the physical location, independent of the entity that owns the relay.

The applicability requirements in proposed Reliability Standard PRC-025-1 and corresponding revisions to the applicability requirements in proposed Reliability Standard PRC-023-3 address the Commission's concern that all generator and GSU transformer load-responsive protective relays are subject to appropriate requirements in a Reliability Standard.

B. Enforceability of proposed Reliability Standard PRC-023-3

The proposed Reliability Standard PRC-023-3 contains Measures that support the Requirements by clearly identifying acceptable evidence of compliance and how the

Requirements will be enforced. The Implementation Plan also discusses the documentation necessary to comply with the proposed Reliability Standard. The VSLs provide further guidance on the processes through which NERC will enforce the Requirements of the proposed Reliability Standard. The VRFs and VSLs for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment. The VSLs have been developed based on the situations an auditor may encounter during a compliance audit.

III. MINORITY UNIT AUXILIARY TRANSFORMER ISSUE

As discussed in the petition for proposed Reliability Standard PRC-025-1, minority comments raised questions as to whether the low-voltage side relays of unit auxiliary transformers ("UAT") should be included in the proposed Reliability Standard. The standard drafting team has studied this issue and determined there is no adverse reliability impact created by the Reliability Standard as proposed. Based on the standard drafting team's findings, no changes to proposed Reliability Standard PRC-025-1 regarding the addition of low-voltage side relays are necessary at this time. However, NERC staff will implement a recommendation by the standard drafting team to monitor UAT performance through its customary data collection processes.

The standard drafting team has prepared a report on this issue; it is attached to this petition as **Exhibit E.**

IV. CONCLUSION

For the reasons set forth above, NERC respectfully requests that the Commission:

- approve proposed Reliability Standard PRC-023-3 and associated elements included in **Exhibit A,** effective as proposed herein;
- approve the Implementation Plan included in **Exhibit B**; and
- approve the retirement of Reliability Standard PRC-023-2, effective as proposed herein.

Respectfully submitted,

/s/ Brady A. Walker

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Counsel for the North American Electric Reliability Corporation

Date: December 17, 2013

CERTIFICATE OF SERVICE

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

Dated at Washington, D.C. this 17th day of December, 2013.

/s/ Brady A. Walker

Brady A. Walker

Counsel for North American Electric Reliability Corporation

Exhibit A

Proposed Reliability Standard

A. Introduction

1. **Title:** **Transmission Relay Loadability**

2. **Number:** PRC-023-3

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. Functional Entity:

   4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

   4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

   4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

   4.1.4 Planning Coordinator

   4.2. Circuits:

   4.2.1 Circuits Subject to Requirements R1 – R5:

   4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

   4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

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

   4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

   4.2.2 Circuits Subject to Requirement R6:

   4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. **Effective Dates:** See Implementation Plan.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. 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] [Time Horizon: Long Term Planning]*.

Criteria:

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).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).
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:
   - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
   - 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.
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 Requirement R1, criterion 3, using the full line inductive reactance.
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).
6. Not used.

[1] 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.

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.

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.

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.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays 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.

10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 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, for at least 15 minutes to provide time 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 set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

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:

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

b. 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.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

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[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

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. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 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]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-3 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-3, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

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

The Compliance Enforcement Authority shall keep the last audit record 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.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated.	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met

Requirement	Lower	Moderate	High	Severe
		(part 6.2)		6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. 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, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.

PRC-023-3 — 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).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

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

2.1. 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 except as noted in section 1.6.

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

2.4. Not used.

2.5. Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-3 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

A. Introduction

1. **Title:** ~~–~~ **Transmission Relay Loadability**
2. **Number:** PRC-023-~~2~~3
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. Functional Entity:

4.1.1 Transmission ~~Owners~~Owner with load-responsive phase protection systems as described in PRC-023-~~2~~3 - Attachment A, applied ~~to~~at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.2 Generator ~~Owners~~Owner with load-responsive phase protection systems as described in PRC-023-~~2~~3 - Attachment A, applied ~~to~~at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution ~~Providers~~Provider with load-responsive phase protection systems as described in PRC-023-~~2~~3 - Attachment A, applied ~~to~~at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

4.1.4 Planning ~~Coordinators~~Coordinator

4.2. Circuits~~-~~:

4.2.1 Circuits Subject to Requirements R1 – R5:

4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

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

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6:

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

~~4.2.2.2~~ Transmission lines operated ~~below100~~below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES

~~**5. Effective Dates**~~

4.2.2.2 ~~The effective dates of~~, except Elements that connect the ~~requirements in the PRC-023-2 standard corresponding~~GSU transformer(s) to the ~~applicable Functional Entities and circuits~~Transmission system that are ~~summarized in the following table:~~used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

~~Requirement~~	~~Applicability~~	~~Effective Date~~	
		~~Jurisdictions where Regulatory Approval is Required~~	~~Jurisdictions where No Regulatory Approval is Required~~
~~R1~~	~~Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above, except as noted below.~~	~~First day of the first calendar quarter, after applicable regulatory approvals~~	~~First calendar quarter after Board of Trustees adoption~~
	~~• For Requirement R1, criterion 10.1, to set transformer fault protection relays on transmission lines terminated only with a transformer such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability~~	~~First day of the first calendar quarter 12 months after applicable regulatory approvals~~	~~First day of the first calendar quarter 12 months after Board of Trustees adoption~~
	~~• For supervisory elements as described in PRC-023-2 - Attachment A, Section 1.6~~	~~First day of the first calendar quarter 24 months after applicable regulatory approvals~~	~~First day of the first calendar quarter 24 months after Board of Trustees adoption~~
	~~• For switch-on-to-fault schemes as described in PRC-023-2 - Attachment A, Section 1.3~~	~~Later of the first day of the first calendar quarter after applicable regulatory approvals of PRC-023-2 or the first day of the first calendar quarter 39 months following applicable regulatory approvals of PRC-023-1 (October 1, 2013)~~	~~Later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011~~[1]
	~~Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6~~	~~Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2 per~~	~~Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2~~

~~1 July 1, 2011 is the first day of the first calendar quarter 39 months following the Board of Trustees February 12, 2008 approval of PRC-023-1.~~

~~Requirement~~	~~Applicability~~	~~Effective Date~~	
		~~Jurisdictions where Regulatory Approval is Required~~	~~Jurisdictions where No Regulatory Approval is Required~~
		~~application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date~~	~~per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date~~
~~R2 and R3~~	~~Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above~~	~~First day of the first calendar quarter after applicable regulatory approvals~~	~~First day of the first calendar quarter after Board of Trustees adoption~~
	~~Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6~~	~~Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date~~	~~Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date~~

~~Requirement~~	~~Applicability~~	~~Effective Date~~	
		~~Jurisdictions where Regulatory Approval is Required~~	~~Jurisdictions where No Regulatory Approval is Required~~
~~R4~~	~~Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability~~	~~First day of the first calendar quarter six months after applicable regulatory approvals~~	~~First day of the first calendar quarter six months after Board of Trustees adoption~~
~~R5~~	~~Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12~~	~~First day of the first calendar quarter six months after applicable regulatory approvals~~	~~First day of the first calendar quarter six months after Board of Trustees adoption~~
~~R6~~	~~Each Planning Coordinator shall conduct an assessment by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5~~	~~First day of the first calendar quarter 18 months after applicable regulatory approvals~~	~~First day of the first calendar quarter 18 months after Board of Trustees adoption~~

5. Effective Dates: See Implementation Plan.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. 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] [Time Horizon: Long Term Planning]*.

Criteria:

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).

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).

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:

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

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 Requirement R1, criterion 3, using the full line inductive reactance.

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).

~~**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.~~

6. Not used.

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.

[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.

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.

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.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer ~~-~~so that the relays 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.

10.1 Set load~~-~~-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[3].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 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, for at least 15 minutes to provide time 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 set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[4].

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:

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

b. 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.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

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[3] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

[4] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

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. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion ~~6,~~ 7, 8, 9, 12, or 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]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-~~2~~3 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-3, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

~~**6.2**~~

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion ~~6,~~ 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. ~~–~~The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. ~~-~~The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6.~~-~~ The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. Compliance

1. Compliance Monitoring Process

~~**1.1. Compliance Monitoring Responsibility**~~

1.1. ~~For entities that do not work for the Regional Entity, the Regional Entity shall serve as the~~ **Compliance Enforcement Authority**~~.~~

~~For functional entities that work for their Regional Entity, the ERO shall serve as the~~ As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority~~.~~" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

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

The Compliance ~~Monitor~~Enforcement Authority shall keep the last audit record 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.

2. **Violation Severity Levels:**

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 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~~BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion ~~6,~~ 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated.	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must

Requirement	Lower	Moderate	High	Severe
		(part 6.2)		comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. 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, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	November 7, 2013	Adopted by NERC Board of Trustees	Supplemental SAR to Clarify applicability for consistency with PRC-025-1 and other minor corrections.

PRC-023-3 — 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).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

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

2.1. 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 except as noted in section 1.6.

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

~~**2.4.** Generator protection relays that are susceptible to load.~~

2.4. Not used.

2.5. Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-3 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the ~~BES~~Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is a monitored Facility of an ~~IROL,~~Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[5] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

[5] ~~-~~ Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

~~**B6.**~~ The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

B6.

Exhibit B

Implementation Plan

Implementation Plan

PRC-023-3 – Transmission Relay Loadability

Project 2010-13.2 Phase II Relay Loadability

Requested Approvals

- PRC-023-3 – Transmission Relay Loadability

Requested Retirements

- PRC-023-2 – Transmission Relay Loadability

Prerequisite Approvals

- PRC-025-1 – Generator Relay Loadability*
  *A supplemental SAR was approved by the Standards Committee at their January 16-17, 2013 meeting to authorize the drafting team to make changes to PRC-023-2 to comport with the proposed draft PRC-025-1 – Generator Relay Loadability in order to establish a bright line between the applicability of load-responsive protective relays in the current transmission and the proposed generator relay loadability standards.

Revisions to Defined Terms in the NERC Glossary

- None

Background

The generator relay loadability standard drafting team and industry stakeholders raised a concern that there is no bright line to clearly distinguish which load-responsive protective relays pertain to the existing PRC-023-2 – Transmission Relay Loadability standard, effective in the United States on July 1, 2012, and the proposed PRC-025-1 – Generator Relay Loadability standard. To resolve this concern, the drafting team proposed to modify the applicability section of PRC-023-2. The standard drafting team clarified, for each functional entity, the applicability of PRC-023-2 by tying applicability to the terminal the load-responsive protective relay that it is connected to within the Transmission system.

General Considerations

It is expected that the implementation period for PRC-023-2 will have been achieved, in part, by the time PRC-023-3 is adopted by the NERC Board of Trustees and by the time of other approvals by applicable

governmental authorities. The proposed PRC-023-3 Implementation Plan now reflects specific milestone dates that are known time periods consistent with PRC-023-2.

Applicable Entities

- Distribution Provider
- Generator Owner
- Planning Coordinator
- Transmission Owner

Effective Date

New Standard

PRC-023-3	First day of the first calendar quarter 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 calendar quarter 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.

Standards for Retirement

PRC-023-2	Midnight of the day immediately prior to the Effective Date of PRC-023-3 – Transmission Relay Loadability in the particular jurisdiction in which the new standard is becoming effective, except Requirement R1, Criterion 6 which will remain in force until the effective date of PRC-025-1.

Implementation Plan for Definitions

No definitions are proposed as a part of this standard.

Implementation Plan for PRC-023-3, Requirements R1 through R6

Each Distribution Provider, Generator Owner, Planning Coordinator, and Transmission Owner applicable to this standard shall be 100% compliant on the following dates:

Requirement	Applicability	Implementation Date: Jurisdictions where Regulatory Approval is Required	Implementation Date: Jurisdictions where No Regulatory Approval is Required
R1	Each Transmission Owner, Generator Owner, and Distribution Provider with load-responsive phase protection systems on transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above, except as noted below.	First day of the first calendar quarter, after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
	• For supervisory elements as described in PRC-023-3 - Attachment A, Section 1.6	The later of July 1, 2014 or first day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
	• For switch-on-to-fault schemes as described in PRC-023-3 - Attachment A, Section 1.3	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1 (continued)	Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date
R2 and R3	Each Transmission Owner, Generator Owner, and Distribution Provider with load-responsive phase protection systems on transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R2 and R3 continued	Each Transmission Owner, Generator Owner, and Distribution Provider with load-responsive phase protection systems on circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date
R4	Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability	First day of the first calendar quarter six months after applicable regulatory approvals	First day of the first calendar quarter six months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R5	Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
R6 (including parts 6.1 and 6.2)	Each Planning Coordinator shall conduct an assessment by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owner, and Distribution Providers must comply with Requirements R1 through R5	Later of January 1, 2014 or the first day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Revisions or Retirements to Already Approved Standards

The following table identifies the sections of the approved standard that shall be added, retired, or revised when this standard is implemented. If the drafting team is recommending revisions, those changes are identified by the "Proposed Replacement" column.

Already Approved Standard	Proposed Replacement
PRC-023-2 **4.1.** Functional Entity **4.1.1** Transmission Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* **4.1.2** Generator Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* **4.1.3** Distribution Providers with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1*(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities. **4.1.4** Planning Coordinators	**PRC-023-3** **4.1.** Functional Entity **4.1.1** Transmission Owner with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* **4.1.2** Generator Owner with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* **4.1.3** Distribution Provider with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities. **4.1.4** Planning Coordinator
Notes: The change in the proposed PRC-023-3 Applicability, Section 4.1, Functional Entity creates a bright line between those load-responsive protective relays that are applicable to PRC-023-3 – Transmission Relay Loadability and the proposed PRC-025-1 – Generator Relay Loadability. This is evident by the minor changes to the Applicability text to distinguish the applicability of the relays by which "terminal" the load-responsive protective relay is connected to within the Transmission system. Applicability is established by ownership of the load-responsive protective relays, not the Facilities.	

Already Approved Standard	Proposed Replacement
PRC-023-2 **4.2.** Circuits **4.2.1** Circuits Subject to Requirements R1 – R5 **4.2.1.1** Transmission lines operated at 200 kV and above. **4.2.1.2** Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6. **4.2.1.3** Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6. **4.2.1.4** Transformers with low voltage terminals connected at 200 kV and above. **4.2.1.5** Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6. **4.2.1.6** Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6. **4.2.2** Circuits Subject to Requirement R6	**PRC-023-3** **4.2.** Circuits **4.2.1** Circuits Subject to Requirements R1 – R5 **4.2.1.1** Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. **4.2.1.2** Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6. **4.2.1.3** Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6. **4.2.1.4** Transformers with low voltage terminals connected at 200 kV and above. **4.2.1.5** Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6. **4.2.1.6** Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6. **4.2.2** Circuits Subject to Requirement R6

Already Approved Standard	Proposed Replacement
4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV **4.2.2.2** Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES	**4.2.2.1** Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. **4.2.2.2** Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.
Notes: The change in the proposed PRC-023-3 Applicability, Section 4.1 Facilities, creates a bright line between those Facilities that are applicable to PRC-023-3 – Transmission Relay Loadability and those Facilities in the proposed PRC-025-1 – Generator Relay Loadability. This is achieved by excluding Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant while allowing these Elements to also supply generating plant loads. Plant loads may include situations like pumped storage facilities where the generating plant also serves as a load for pumping. The above applicability items for Section 4.2 "Circuits" that are subject to the standard were modified to exclude those Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. The added text reads: "except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads" and is found in Sections 4.2.1.1, 4.2.2.1, and 4.2.2.2. This eliminates an overlap with PRC-025-1 and places the performance for lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network under the proposed PRC-025-1 with the understanding that these Elements may also supply generating plant loads.	

Already Approved Standard	Proposed Replacement
PRC-023-2 (Retirement) R1, Criterion 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."	**PRC-025-1 (New)** **New Requirement** R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]* *Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria, Options 14 through 19. (See standard for details)
Notes: The Transmission Owner and Distribution Provider were added to the Applicability of the proposed PRC-025-1 and excluded Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. Therefore, Requirement R1, Criterion 6 has been removed from the proposed standard PRC-023-3 because this criterion is now replaced (i.e., superseded) by the proposed PRC-025-1 – Generator Relay Loadability standard, Requirement R1 and its Attachment 1: Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria, Options 14 through 19. Applicability concerning generation Facilities is now addressed in the proposed PRC-025-1. Although, Requirement R1, Criterion 6 is not shown in the proposed PRC-023-3, it remains auditable while each entity assures its compliance with the proposed PRC-025-1 criteria according to the provided Implementation Plan(s).	
PRC-023-2 (Retirement) R1, Attachment A, exclusion 2.4. "Generator protection relays that are susceptible to load."	**None.**
Notes: This exclusion has been superseded by the proposed PRC-025-1 standard that pertains to these relays. The proposed PRC-023-3 standard does not include any criteria that are relevant to generator protection relays. The proposed PRC-025-1 standard establishes specific criteria for generator load-responsive protective relays, and renders this exclusion unnecessary.	

Exhibit C

Order No. 672 Criteria

Exhibit C—Order No. 672 Criteria—Proposed Reliability Standard PRC-023-3—Transmission Relay Loadability

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how the proposed Reliability Standard has met or exceeded the criteria:

1. Proposed Reliability Standards must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve that goal.[2]

The proposed standard achieves the specific reliability goal of ensuring that Reliability Standards are clear and unambiguous in their Applicability. This is accomplished by inserting clarifying language regarding the applicability of proposed Reliability Standard PRC-023-3 and thereby strengthening the previously submitted and currently pending proposed Reliability Standard PRC-025-1 as a response to Commission directives.

2. Proposed Reliability Standards must be applicable only to users, owners and operators of the bulk power system, and must be clear and unambiguous as to what is required and who is required to comply.[3]

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[1] *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, FERC Stats. & Regs. ¶ 31,204, *order on reh'g*, Order No. 672-A, FERC Stats. & Regs. ¶ 31,212 (2006).

[2] Order No. 672 at P 321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of Bulk-Power System facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to Cybersecurity protection.

Order No. 672 at P 324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons.

[3] Order No. 672 at P 322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others.

The proposed Reliability Standard is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. The proposed Reliability Standard applies to Distribution Providers, Generator Owners, Planning Coordinators, and Transmission Owners and clearly articulates the actions that such entities must take to comply with the proposed Reliability Standard.

3. A proposed Reliability Standard must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation.[4]

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment. The VRFs and VSLs in the proposed Reliability Standard have not been revised; the VRFs and VSLs contained in Reliability Standard PRC-023-2[5] will remain in effect upon approval of proposed Reliability Standard PRC-023-3.

4. A proposed Reliability Standard must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non preferential manner.[6]

The proposed Reliability Standard contains Measures that support each Requirement by clearly identifying what is required and how the Requirement will be enforced. The Measures in the proposed Reliability Standard have not been revised; the Measures contained in Reliability

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Order No. 672 at P 325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability.

4 Order No. 672 at P 326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply.

5 Available at: http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-023-2&title=Transmission%20Relay%20Loadability&jurisdiction=United%20States

6 Order No. 672 at P 327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.

Standard PRC-023-2[7] will remain in effect upon approval of proposed Reliability Standard PRC-023-3.

5. Proposed Reliability Standards should achieve a reliability goal effectively and efficiently — but do not necessarily have to reflect "best practices" without regard to implementation cost or historical regional infrastructure design.[8]

The proposed Reliability Standard achieves its reliability goals effectively and efficiently in accordance with Order No. 672. With a clear distinction between proposed Reliability Standards PRC-023-3 and PRC-025-1, Entities are now able to effectively implement both Reliability Standards, in accordance with Commission directives, without the risk of inconsistent compliance and enforcement procedures.

6. Proposed Reliability Standards cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect Bulk-Power System reliability. Proposed Reliability Standards can consider costs to implement for smaller entities, but not at consequences of less than excellence in operating system reliability.[9]

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. To the contrary, the proposed standard represents a significant improvement over the previous version as described herein. By providing clarity in Applicability, the risk of redundant compliance violations is significantly decreased making the proposed Reliability Standard much

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[7] Available at: http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=PRC-023-2&title=Transmission%20Relay%20Loadability&jurisdiction=United%20States

[8] Order No. 672 at P 328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently.

[9] Order No. 672 at P 329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator" — if such practice does not adequately protect Bulk-Power System reliability. Although FERC will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability.

Order No. 672 at P 330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it.

more effectively enforceable and understandable to industry. These revisions also support the Commission's directives that lead to the development of proposed Reliability Standard PRC-025-1, which is currently pending before the Commission.

7. Proposed Reliability Standards must be designed to apply throughout North America to the maximum extent achievable with a single Reliability Standard while not favoring one geographic area or regional model. It should take into account regional variations in the organization and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.[10]

The proposed Reliability Standard applies throughout North America and does not favor one geographic area or regional model.

8. Proposed Reliability Standards should cause no undue negative effect on competition or restriction of the grid beyond any restriction necessary for reliability.[11]

Proposed Reliability Standard PRC-023-3 has no undue negative impact on competition. The proposed Reliability Standard requires the same performance by each of the applicable Functional Entities.

The proposed Reliability Standard does not unreasonably restrict the available transmission capability or limit use of the Bulk-Power System in a preferential manner. The

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[10] Order No. 672 at P 331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard.

[11] Order No. 672 at P 332. As directed by section 215 of the FPA, FERC itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another.

Requirements in the proposed Reliability Standard have been clarified to further enable Entities to meet important reliability goals.

9. The implementation time for the proposed Reliability Standard is reasonable.[12]

The proposed effective dates for the standard are just and reasonable and appropriately balance the urgency in the need to implement the standards against the reasonableness of the time allowed for those who must comply to develop necessary procedures, software, facilities, staffing or other relevant capability. This will allow applicable entities adequate time to ensure compliance with the Requirements. The proposed effective dates are explained in the proposed Implementation Plan, attached as **Exhibit B**.

10. The Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[13]

The proposed Reliability Standard was developed in accordance with NERC's Commission-approved, ANSI- accredited processes for developing and approving Reliability Standards. **Exhibit D** includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the proposed Reliability Standard.

These processes included, among other things, multiple comment periods, pre-ballot review periods, and balloting periods. Additionally, all meetings of the standard drafting team were properly noticed and open to the public. The initial and recirculation ballots both achieved

[12] Order No. 672 at P 333. In considering whether a proposed Reliability Standard is just and reasonable, FERC will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability.

[13] Order No. 672 at P 334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by FERC.

a quorum and exceeded the required ballot pool approval levels.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[14]

NERC has identified no competing public interests regarding the request for approval of this proposed Reliability Standard. No comments were received that indicated the proposed Reliability Standard conflicts with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[15]

No other negative factors relevant to whether the proposed Reliability Standard is just and reasonable were identified.

[14] Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

[15] Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

accordance with the Commission-approved Reliability Standard development process.[11]

The proposed Reliability Standard was developed in accordance with NERC's Commission-approved, ANSI- accredited processes for developing and approving Reliability Standards. **Exhibit D** includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the proposed Reliability Standard.

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[12] Order No. 672 at P 335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard.

[13] Order No. 672 at P 323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.

Exhibit D

Summary of Development History and Complete Record of Development

Exhibit D—Summary of the Reliability Standard Development Proceeding and Complete Record of Development of Proposed Reliability Standard PRC-023-3—Transmission Relay Loadability

The development record for proposed Reliability Standard EOP-010-1 is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the ERO.[1] The technical expertise of the ERO is derived from the standard drafting team. For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences.

II. Standard Development History

A. Standard Authorization Request Development

A supplemental Standard Authorization Request ("SAR") to revise Reliability Standard PRC-023-2 was submitted on November 30, 2013 and approved by the Standards Committee ("SC") on January 18, 2013.

The supplemental SAR was posted for a 45-day public comment period from January 25, 2013 through March 11, 2013. There were 20 sets of responses, including comments from approximately 89 individuals from approximately 54 companies representing 9 of the 10 Industry Segments. The standard drafting team made no changes to the supplemental SAR after considering comments submitted.

B. First Posting

Proposed Reliability Standard PRC-023-3 was posted for a 30-day public comment period from April 25, 2013 through May 24, 2013. There were 51 sets of responses, including

[1] Section 215(d)(2) of the Federal Power Act; 16 U.S.C. §824(d)(2) (2006).

comments from approximately 166 individuals from approximately 92 companies representing 9 of the 10 Industry Segments.

The standard drafting team considered stakeholder comments and made the following changes to proposed Reliability Standard PRC-023-3 based on those comments:

- The most significant change was the removal of the previously proposed Requirements R7 and R8 which applied to the generator interconnection Facility and generator step-up transformer applicable to the Distribution Provider and Transmission Owner. With this change the standard drafting team added the Distribution Provider and Transmission Owner to the applicability of proposed Reliability Standard PRC-025-1 and removed the applicability of those lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network from proposed Reliability Standard PRC-023-3. This change establishes a bright line distinction between the two Reliability Standards.

- The following changes were made to the Applicability section:
  - Removed references to Requirements R7 and R8
  - Added the exception to sections 4.2.1.1, 4.2.2.1, and 4.2.2.2 to exclude lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network
  - Removed the sections 4.2.3 and 4.2.4

- The following changes were made to the Requirements section:
  - Requirement R1, criterion 6 was removed to comport with the elimination of addressing load-responsive protective relays on lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network

- The following changes were made to the Measures section:
  - Removed the proposed Requirement R7
  - Removed the proposed Requirement R8

- The following changes were made to the Compliance section:
  - Removed references to Requirements R7 and R8

- The following changes were made to the Violation Severity Levels:
  - Removed Requirements R7 and R8

- The following change was made to Attachment A:
  - Revised criterion 2.4 as “Note Used” since it is no longer needed

- The following change was made to Attachment C:
  - Removed due to the removal of Requirements R7 and R8

- The following changes were made to the Implementation Plan:

- Updated to reflect the transition of PRC-023-3 Requirement R1, Criterion 6 to the proposed criterion in proposed Reliability Standard PRC-025-1

- The following changes were made to the VRF/VSL Justifications:
  - References to Requirement R1, Criterion 6 were removed

C. Second Posting

Proposed Reliability Standard PRC-023-3 was posted for a 45-day public comment period from June 20, 2013 through August 8, 2013. There were 27 sets of responses, including comments from approximately 90 individuals from approximately 76 companies representing 9 of the 10 Industry Segments.

The standard drafting team considered stakeholder comments and made the following changes to proposed Reliability Standard PRC-023-3 based on those comments:

- In the Applicability section, Sections 4.2.1.1, 4.2.2.1, and 4.2.2.2 were revised to clarify the applicability by removing "except lines that are used exclusively to export energy directly from a Bulk Electric System (BES) generating unit or generating plant to the network" and replacing it with "except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads."

- In the Implementation Plan, the phrase "load-responsive phase protection systems on" was inserted on Requirements R1, R2, and R3 Applicability of the Implementation Plan to clarify that the "Applicability" column is referring to the ownership of the relays applied on transmission lines and not the ownership of the line. Requirement R6 was clarified that it includes Parts 6.1 and 6.2.

D. Initial Ballot

Proposed Reliability Standard PRC-023-3 was posted for an initial ballot period on July 26, 2013 through August 8, 2013. The proposed Reliability Standard received a quorum of 80.05% and an approval rating of 93%.

E. Final Ballot

Proposed Reliability Standard PRC-023-3 was posted for a 10-day final ballot period on September 4, 2013 through September 13, 2013. The proposed Reliability Standard received a quorum of 85.93% and an approval rating of 90.83%.

F. Board of Trustees Approval

Proposed Reliability Standard PRC-023-3 was approved by the NERC Board of Trustees on November 7, 2013.

Project 2010-13.2 Phase 2 Relay Loadability: Generation

Related Files

Status:

PRC-023-3 was adopted by the NERC Board of Trustees on November 7, 2013.

PRC-025-1 was adopted by the NERC Board of Trustees on August 15, 2013**.**

Background:

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, developing a new Reliability Standard to address three areas of relay loadability that include modifications to the approved PRC-023-1, developing a new Reliability Standard to address generator protective relay loadability, and another Reliability Standard to address the operation of protective relays due to power swings. This project's SAR addresses these directives and establishes a three-phased approach to standard development.

Phase 2 is focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. This Reliability Standard establishes requirements for the Generator Operator functional entity to set protective relays at a level such that generating units do not trip during system disturbances that are not damaging to the generator thereby unnecessarily removing the generator from service.

Phase 1 was focused on making the specific modifications to PRC-023-1 and was completed in the approved PRC-023-2 Reliability Standard, which became mandatory on July 1, 2012. Phase 3, which will follow this project, will focus on developing requirements that address protective relay operations due to stable power swings.

Purpose / Industry Need:

During analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This unnecessary tripping has often been evaluated to have extended the scope and/or duration of that disturbance. This was noted, in detail, to be a serious issue in the August 2003 "blackout' in the northeastern North American continent.

During the recoverable phase of a disturbance, the disturbance may exhibit a "voltage disturbance" behavior pattern, where system voltage is widely depressed. In order to support the system during this phase of a disturbance, this standard establishes criteria for setting load-responsive relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from that voltage disturbance. Premature or unnecessary tripping of generators during this period can deepen the severity of the voltage disturbance due to removal of dynamic Reactive Power, and change the character of the disturbance such that it is less recoverable.

Draft	Action	Dates	Results	Consideration of Comments
Draft 4 **PRC-023-3** Clean **(28)** | Redline to Last Posting	**Final Ballot** **Info>> (33)**	09/04/13 - 09/13/13 (closed)	Summary>>**(34)** Ballot Results>> **(35)**	

(29)| Redline to Last Approved (30) **Implementation Plan** Clean (31)| Redline (32)	**Vote>>**			
Draft 5 **PRC-025-1** Clean | Redline to Last Posting (Redline Corrected 08/05/13) Implementation Plan **Supporting Materials:** **Guideline and Technical Basis** Clean | Redline to Last Posting VRF/VSL Justification	Final Ballot Updated Info>> Vote>>	08/02/13 - 08/12/13 (closed)	Summary>> Ballot Results>>	
Draft 4 **PRC-025-1** Clean | Redline to Last Posting **Implementation Plan** Clean | Redline to Last Posting **Guideline and**	Successive Ballot and Non-binding Poll for PRC-025-1 Updated Info>> Vote>>	07/10/13 – 07/19/13 (Closed)	Summary>> Ballot Results>>	

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Clean | Redline to Last Posting

Draft 3
PRC-023-3
Clean (18)| Redline to Last Posting (19)

Implementation Plan
Clean (20) | Redline to Last Posting (21)

Supporting Materials:
Unofficial Comment Form (Word)
PRC-025-1
PRC-023-3 (22)

VRF/VSL Justification for PRC-025-1
Clean | Redline to Last Posting

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Clean | Redline to Last Posting Guideline and Technical Basis Clean | Redline to Last Posting Draft 2 PRC-023-3 Clean **(9)**| Redline to Last Posting **(10)** Implementation Plan Clean **(11)**| Redline to Last Posting **(12)** Supporting Materials: Unofficial Comment Form (Word) **(13)** VRF/VSL Justification for PRC-025-1 Clean | Redline to Last Posting Consideration of Issues and Directives for PRC-025-1 VRF/VSL Justification for PRC-023-3 **(14)**	Vote>>		Non-binding Poll Results>>	
	Comment Period for PRC-025-1 and PRC-023-3 Info>>**(15)** Submit Comments>>	04/25/13 - 05/24 13 (closed)	Comments Received>>**(16)**	Consideration of Comments>>**(17)**

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Implementation Plan
Clean | Redline to Last Posting

Guideline and Technical Basis
Clean | Redline to Last Posting

VRF/VSL Justification

Consideration of Issues and Directives

Draft 1

Supplemental SAR for Relay Loadability Order 733 to revise PRC-023-2 (1)

PRC-023-3
Clean (2)| Redline to Last Approved (3)

PRC-023-3 Implementation Plan (4)

Supporting Materials:

Unofficial Comment Forms (Word)
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Supplemental SAR (5)
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Draft 1 **PRC-025-1** **Implementation Plan** Clean **Supporting Materials: SAR for Relay Loadability Modifications and Additions** clean | Redline to last posting **Unofficial Comment Form (Word)** SAR for Relay Loadability PRC-023-2 Draft SAR Version 1	Comment Period Submit Comments>> Info>>	10/5/2012 - 11/5/2012 (Closed)	Comments Received>>	Consideration of Comments>>

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request Form

Supplemental SAR for Project 2010-13.2 Relay Loadability Order 733 Phase 2 (Relay Loadability: Generation)	
Request Date	11/30/2012
SC Approval Date	01/18/2013
Revised Date	

SAR Requester Information		**SAR Type** (Check a box for each one that applies.)	
Name Howard Gugel, Director of Standards Development		☐	New Standard
Primary Contact Scott Barfield-McGinnis, Standards Developer		☒	Revision to existing Standard
Telephone Fax	404-446-9689	☐	Withdrawal of existing Standard
E-mail	scott.barfield@nerc.net	☐	Urgent Action

Purpose Prevent a potential compliance overlap with the current Reliability Standard PRC-023-2 – Transmission Relay Loadability, which became effective July 1, 2012. The overlap would be created when the proposed PRC-025-1 – Generator Relay Loadability, which is currently under development, is approved and becomes effective.
Industry Need The generator relay loadability standard drafting team identified conditions in the development of the drafting of the PRC-025-1 standard that would create the potential for overlap (e.g., "double jeopardy") and confusion as to which standard is applicable to the Generator Owner entity (i.e., PRC-023-2 or PRC-025-1).
Brief Description This request includes modifying PRC-023-2 to add clarity to the Applicability section of the PRC-023-2 standard. Other modifications include updating references from the version number to reflect the new version number. Detail regarding the effective dates may be removed as the new version is anticipated to become approved beyond the implementation plan for the current version.
Detailed Description The generator relay loadability standard drafting team (GENRLOSDT) continues to evaluate the best alternative to modifying PRC-023-2 to clarify the Generator Owner's applicability with regard to load-responsive protective relays. The drafting team has provided a redline draft to PRC-023-2 with a proposed solution to the issue; however, the drafting team recognizes that the draft PRC-025-1 may provide the opportunity to remove the Generator Owner from PRC-023-2 and therefore eliminate the overlap and confusion without creating a gap in reliability. The drafting team considered whether changes would be necessary to Requirement R1, criterion 6 and decided it should remain in the standard as there may be cases where PRC-023 will be applicable to lines that connect generation stations remote to load. The drafting team has not revealed any concerns about this criterion in relation to the proposed PRC-025-1 standard currently being drafted. The effective date of the draft PRC-023-3 is anticipated to occur beyond the Implementation Plan approved in version two; therefore, the effective date tables are proposed for removal. If an interim implementation is required to bridge PRC-023-2 to the next version, the standard drafting team will modify the effective date tables accordingly. A complete review of the standard will be conducted to reveal any editorial edits that may be needed to improve the quality of the Reliability Standard. Industry commenting, balloting, and approval of the revisions to the draft PRC-023-3 standard will occur contemporaneously with the drafting of the proposed PRC-025-1 standard. Adoption of PRC-023-3 will contingent upon PRC-025-1.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☐	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☒	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within its portion of the Planning Coordinator's Area.
☒	Transmission Owner	Owns and maintains transmission facilities.
☐	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within the Transmission Planner Area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☐	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☐	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
None.	

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	None.
FRCC	None.
MRO	None.
NPCC	None.
RFC	None.
SERC	None.
SPP	None.
WECC	None.

A. Introduction

1. **Title: Transmission Relay Loadability**
2. **Number:** PRC-023-3
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. Functional Entity

4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinator

4.2. Circuits

4.2.1 Circuits Subject to Requirements R1 – R5

4.2.1.1 Transmission lines operated at 200 kV and above.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

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

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

4.2.2 Circuits Subject to Requirement R6

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES

5. **Effective Dates**

First day of the first calendar quarter 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 calendar quarter 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

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. 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] [Time Horizon: Long Term Planning]*.

Criteria:

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).

2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).

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:

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

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 Requirement R1, criterion 3, using the full line inductive reactance.

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).

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.

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.

[1] 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.

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.

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.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays 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

10.1 Set load responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 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, for at least 15 minutes to provide time 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 set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

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:

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

b. 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.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

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.

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[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration,* Clause 4.4, Figure 4

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 6, 7, 8, 9, 12, or 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]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-3 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-3, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

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

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in R6. The Planning Coordinator shall retain the most recent list of circuits in its

Planning Coordinator area for which applicable entities must comply with the standard, as determined per R6.

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

The Compliance Enforcement Authority shall keep the last audit record 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.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 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. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 6, 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated.	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must

Requirement	Lower	Moderate	High	Severe
		(part 6.2)		comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. 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, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

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Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	TBD	Clarify applicability for consistency with PRC-025-1 and other minor corrections	Supplemental SAR (Project 2010-13.2)

PRC-023-3 — 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).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

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

2.1. 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 except as noted in section 1.6

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

2.4. Generator protection relays that are susceptible to load.

2.5. Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-3 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is a monitored Facility of an IROL, where the IROL was determined in the planning horizon pursuant to FAC-010.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

A. Introduction

1. **Title: Transmission Relay Loadability**

2. **Number:** PRC-023-~~2~~3

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. Functional Entity

4.1.1 Transmission Owner~~s~~ with load-responsive phase protection systems as described in PRC-023-~~2~~3 - Attachment A, applied ~~to~~at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).*

4.1.2 Generator Owner~~s~~ with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied ~~to~~at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).*

4.1.3 Distribution Provider~~s~~ with load-responsive phase protection systems as described in PRC-023-~~2~~3 - Attachment A, applied ~~to~~at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinator~~s~~

4.2. Circuits

4.2.1 Circuits Subject to Requirements R1 – R5

4.2.1.1 Transmission lines operated at 200 kV and above.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

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

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

4.2.2 Circuits Subject to Requirement R6

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES

5. Effective Dates

~~The effective dates of the requirements in the PRC-023-2 standard corresponding to the applicable Functional Entities and circuits are summarized in the following table:~~

~~Requirement~~	~~Applicability~~	~~Effective Date~~	
		~~Jurisdictions where Regulatory Approval is Required~~	~~Jurisdictions where No Regulatory Approval is Required~~
	~~Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above, except as noted below.~~	~~First day of the first calendar quarter, after applicable regulatory approvals~~	~~First calendar quarter after Board of Trustees adoption~~
	~~• For Requirement R1, criterion 10.1, to set transformer fault protection relays on transmission lines terminated only with a transformer such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability~~	~~First day of the first calendar quarter 12 months after applicable regulatory approvals~~	~~First day of the first calendar quarter 12 months after Board of Trustees adoption~~
	~~• For supervisory elements as described in PRC-023-2 - Attachment A, Section 1.6~~	~~First day of the first calendar quarter 24 months after applicable regulatory approvals~~	~~First day of the first calendar quarter 24 months after Board of Trustees adoption~~
~~R1~~	~~• For switch-on-to-fault schemes as described in PRC-023-2 - Attachment A, Section 1.3~~	~~Later of the first day of the first calendar quarter after applicable regulatory approvals of PRC-023-2 or the first day of the first calendar quarter 39 months following applicable regulatory approvals of PRC-023-1 (October 1, 2013)~~	~~Later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011~~[1]
	~~Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6~~	~~Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2 per~~	~~Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2~~

~~1 July 1, 2011 is the first day of the first calendar quarter 39 months following the Board of Trustees February 12, 2008 approval of PRC-023-1.~~

~~Requirement~~	~~Applicability~~	~~Effective Date~~	
		~~Jurisdictions where Regulatory Approval is Required~~	~~Jurisdictions where No Regulatory Approval is Required~~
		~~application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date~~	~~per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date~~
~~R2 and R3~~	~~Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above~~	~~First day of the first calendar quarter after applicable regulatory approvals~~	~~First day of the first calendar quarter after Board of Trustees adoption~~
	~~Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6~~	~~Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date~~	~~Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date~~

~~Requirement~~	~~Applicability~~	~~Effective Date~~	
		~~Jurisdictions where Regulatory Approval is Required~~	~~Jurisdictions where No Regulatory Approval is Required~~
~~R4~~	~~Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability~~	~~First day of the first calendar quarter six months after applicable regulatory approvals~~	~~First day of the first calendar quarter six months after Board of Trustees adoption~~
~~R5~~	~~Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12~~	~~First day of the first calendar quarter six months after applicable regulatory approvals~~	~~First day of the first calendar quarter six months after Board of Trustees adoption~~
~~R6~~	~~Each Planning Coordinator shall conduct an assessment by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5~~	~~First day of the first calendar quarter 18 months after applicable regulatory approvals~~	~~First day of the first calendar quarter 18 months after Board of Trustees adoption~~

First day of the first calendar quarter 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 calendar quarter 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

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. 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] [Time Horizon: Long Term Planning]*.

Criteria:

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).

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).

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:

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

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 Requirement R1, criterion 3, using the full line inductive reactance.

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).

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.

[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.

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.

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.

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.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays 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

10.1 Set load responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[3].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 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, for at least 15 minutes to provide time 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 set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[4].

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:

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

b. 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.

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[3] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4

[4] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

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. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 6, 7, 8, 9, 12, or 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]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-~~2~~3 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-3, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 6, 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.~~For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority. For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.~~

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its

Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per R6.

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

The Compliance ~~Monitor~~Enforcement Authority shall keep the last audit record 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.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 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. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 6, 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated.	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must

Requirement	Lower	Moderate	High	Severe
		(part 6.2)		comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. 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, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

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Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	TBD	Clarify applicability for consistency with PRC-025-1 and other minor corrections	Supplemental SAR (Project 2010-13.2)

PRC-023-3 — 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).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

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

2.1. 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 except as noted in section 1.6

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

2.4. Generator protection relays that are susceptible to load.

2.5. Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-3 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is a monitored Facility of an IROL, where the IROL was determined in the planning horizon pursuant to FAC-010.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[5] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

[5] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

Implementation Plan
Project 2010-13.2 - Relay Loadability: Generator

Requested Approvals

- PRC-023-3 – Transmission Relay Loadability

Requested Retirements

- PRC-023-2 – Transmission Relay Loadability

Prerequisite Approvals

- PRC-025-1 – Generator Relay Loadability

  A supplemental SAR was approved by the Standards Committee at their January 16-17, 2013 meeting to authorize the drafting team to make changes to PRC-023-2 to comport with the proposed draft PRC-025-1 – Generator Relay Loadability and in order to establish a bright line between the applicability of load-responsive protective relays in the current transmission and the proposed generator relay loadability standards.

Revisions to Defined Terms in the NERC Glossary

- None

Background

The generator relay loadability standard drafting team and industry stakeholders raised a concern about the potential for overlap between existing PRC-023-2 – Transmission Relay Loadability standard, effective in the United States on July 1, 2012, and the proposed PRC-025-1 – Generator Relay Loadability standards. The concern is that there was no bright line to clearly distinguish which load-responsive protective relays pertain to each standard. The drafting team researched the issue and proposed to modify the applicability section of PRC-023-2 to clarify the each functional entity's applicability with respect to which terminal the load-responsive protective relay is connected to within the Transmission system.

General Considerations

The Implementation Plan period reflects consideration that a specific period is not required because no new entity or facilities are subject to compliance. Also, it is expected that implementation plan and period for PRC-023-2 will have been achieved and that it will not need to be considered in conjunction with this revision.

Applicable Entities

- Distribution Provider

- Generator Owner
- Planning Coordinator
- Transmission Owner

Effective Date

New Standard

PRC-023-3	First day of the first calendar quarter 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 calendar quarter 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.

Standards for Retirement

PRC-023-2	Midnight of the day immediately prior to the Effective Date of PRC-023-2 – Transmission Relay Loadability in the particular jurisdiction in which the new standard is becoming effective.

Implementation Plan for Definitions

No definitions are proposed as a part of this standard.

Implementation Plan for PRC-023-3, All requirements

Each Distribution Provider, Generator Owner, Planning Coordinator, and Transmission Owner applicable to this standard shall be 100% compliant on the effective date of the standard according to the jurisdiction.

Revisions or Retirements to Already Approved Standards

The following table identifies the sections of the approved standard that shall be retired or revised when this standard is implemented. If the drafting team is recommending the retirement or revision of a requirement, that text is blue.

Already Approved Standard	Proposed Replacement Requirement(s)
PRC-023-2 4.1. Functional Entity 4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* 4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* 4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1*(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities. 4.1.4 Planning Coordinators	**PRC-023-3** 4.1.Functional Entity 4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023-2 3 - Attachment A, applied **at the terminals of the** ~~to~~ circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* 4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied **at the terminals of the** ~~to~~ circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* 4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023-2 3 - Attachment A, applied **at the terminals of the** ~~to~~ circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities. 4.1.4 Planning Coordinators
Notes: The change in applicability creates a bright line between those load-responsive protective relays that are applicable to PRC-023-3 – Transmission Relay Loadability and the proposed PRC-025-1 – Generator Relay Loadability. This is evident by the minor changes to the applicability text to distinguish the applicability of the relays by which "terminal" the load-responsive protective relay is connected to within the Transmission system.	

Unofficial Comment Form

Project 2010-13.2 – Phase II Relay Loadability: Generator SAR for PRC-023-3

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard Authorization Request (SAR). Comments must be submitted by 8 p.m. ET **Monday, March 11, 2013**. If you have questions please contact Scott Barfield-McGinnis at scott.barfield@nerc.net or by telephone at (404) 446-9689.

http://www.nerc.com/filez/standards/Project_2010-13.2_Summary_Table.html

Background Information

This posting is soliciting informal comment.

The Generator Relay Loadability Standard Drafting Team (GENRLOSDT) continues to evaluate the best alternative to modifying PRC-023-2 to clarify the Generator Owner's applicability with regard to load-responsive protective relays. The drafting team has provided a redline draft to PRC-023-2 with a proposed solution to the issue.

The drafting team considered whether changes would be necessary to Requirement R1, criterion 6 and decided it should remain in the standard as there may be cases where PRC-023 will be applicable to lines that connect generation stations remote to load. The drafting team has not revealed any concerns about this criterion in relation to the proposed PRC-025-1 standard currently being drafted.

The effective date of the draft PRC-023-3 is anticipated to occur beyond the Implementation Plan approved in version two; therefore, the effective date tables are proposed for removal. If an interim implementation is required to bridge PRC-023-2 to the next version, the standard drafting team will modify the effective date tables accordingly.

A complete review of the standard will be conducted to reveal any editorial edits that may be needed to improve the quality of the Reliability Standard.

Industry commenting, balloting, and approval of the revisions to the draft PRC-023-3 standard will occur contemporaneously with the drafting of the proposed PRC-025-1 standard. Adoption of PRC-023-3 will contingent upon PRC-025-1.

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions

The scope of this project includes:

- Adding to each functional entity description, the phrase “at the terminals of the” to specify where the load-responsive protective relay is located
- Update the standard version numbers
- Include any editorial edits or updates to current standard text

1. Do you agree with this scope? If not, please explain.

   ☐ Yes
   ☐ No

   Comments:

2. The SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. Do you agree with the list of proposed applicable functional entities? If no, please explain.

   ☐ Yes
   ☐ No

   Comments:

3. Do the proposed changes in the draft PRC-023-3 – Transmission Relay Loadability create the necessary bright line between the draft PRC-025-1 – Generator Relay Loadability create the bright line between the two standards? If no, please explain what would make the bright line clearer.

   ☐ Yes
   ☐ No

   Comments:

4. Are you aware of any regional variances that will be needed as a result of this project? If yes, please identify the regional variance.

   ☐ Yes
   ☐ No

   Comments:

5. Are you aware of any business practice that will be needed or that will need to be modified as a result of this project? If yes, please identify the business practice.

☐ Yes
☐ No

Comments:

6. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2010-13.2 – Phase 2 of Relay Loadability: Generation

Ballot Pools Forming: January 25 – February 25, 2013
Formal Comment Period: January 25 – March 11, 2013

Additional Documents Posted for Comment:
Cost Effectiveness Comment Period: January 25 – March 11, 2013
Supplemental SAR Informal Comment Period: January 25 – March 11, 2013
RSAW Posted for Industry Comments: January 25 – March 11, 2013

Upcoming:
Initial Ballot and Non-Binding Poll: March 1 – March 11, 2013

Now Available

A formal comment period for **PRC-025-1** – Generator Relay Loadability is open through **8 p.m. Eastern on Monday, March 11, 2013** and ballot pools are forming through **8 a.m. Monday, February 25, 2013** (*please note that ballot pools close at 8 a.m. Eastern and mark your calendar accordingly*).

An initial ballot of **PRC-025-1** and non-binding poll of the associated VRFs and VSLs will also be conducted during this period, beginning on **Friday, March 1, 2013** through **8 p.m. Eastern on Monday, March 11, 2013**.

Alongside the comment period, three additional documents will be posted for industry comment: a draft cost effective analysis (CEA), a supplemental SAR, and a draft Reliability Standard Audit Worksheet (RSAW).

In response to concerns expressed by stakeholders and regulators, NERC has developed a Cost Effective Analysis Process (CEAP) to introduce the concept of cost consideration and effectiveness into the development of new and revised standards. As part of the pilot of the CEAP, NERC is proposing to conduct a CEA to provide information about cost impacts of draft Reliability Standards and their relative effectiveness, which will allow the industry to evaluate and propose alternative approaches for achieving the reliability objectives of the standard. The revisions under Project 2010-13.2 have been deemed to be required to meet an adequate level of reliability, and therefore, “Phase I” of the CEAP (a cost impact assessment) is unnecessary. A pilot of “Phase II” of the CEAP, the CEA, is posted for industry comment through **8 p.m. Eastern on Monday, March 11, 2013**. More information about the CEAP is available on the project page.

A supplemental SAR has also been developed to revise PRC-023-2 and is posted for an informal comment period.

Finally, PRC-025-1 was drafted in conjunction with the development of its RSAW, which is posted for an informal comment period.

Instructions for Joining Ballot Pool(s)

Ballots pools are being formed for the standard and non-binding poll for PRC-025-1. Registered Ballot Body members must join both ballot pools to be eligible to vote in the balloting of PRC-025-1 and to submit an opinion for the non-binding poll of the associated VRFs and VSLs. Registered Ballot Body members may join the ballot pools at the following page: Join Ballot Pool.

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

Initial ballot: bp-2010-13.2_PRC-025-1_in@nerc.com
Non-binding poll: bp-2010-13.2_NB_PRC-025_in@nerc.com

Instructions for Commenting

A formal comment period is open for PRC-025-1 through **8 p.m. Eastern on Monday, March 11, 2013**. The supplemental SAR to revise PRC-023-2 and CEA have also been posted for industry comment. Please use the links below to the electronic comment forms to submit comments:

PRC-025-1
Supplemental SAR
Cost Effective Analysis

If you experience any difficulties in using the electronic form, please contact Wendy Muller at wendy.muller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

A comment period on the draft RSAW is open through **8 p.m. Eastern on Monday, March 11, 2013**. The draft RSAW is posted on the NERC Compliance Reliability Standard Audit Worksheet page. Please submit comments on the draft RSAW by using the RSAW feedback form on the project page and sending to: RSAWfeedback@nerc.net.

Next Steps

An initial ballot will be conducted **March 1, 2013** through 8 p.m. **Monday, March 11, 2013**.

Background

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, developing a new Reliability Standard to address generator protective relay loadability, and developing another Reliability Standard to address the operation of protective relays due to power swings. This project's SAR addresses these directives and establishes a three-phase approach to standard development.

Phase I was focused on making the specific modifications to PRC-023-1 and was completed in the approved PRC-023-2 Reliability Standard, which became mandatory on July 1, 2012. This project, Phase II, is focused on developing a new Reliability Standard, PRC-025-1 – Generator Relay Loadability, to address generator protective relay loadability. This Reliability Standard establishes requirements for the Generator Operator functional entity to set protective relays at a level such that generating units do not trip during system disturbances that are not damaging to the generator thereby unnecessarily removing the generator from service. Phase III, which will follow this project, will focus on developing requirements that address protective relay operations due to stable power swings.

Additional information can be found on the project page.

Standards Development Process

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

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

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Name (9 Responses)
Organization (9 Responses)
Group Name (11 Responses)
Lead Contact (11 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (0 Responses)
Comments (20 Responses)
Question 1 (19 Responses)
Question 1 Comments (20 Responses)
Question 2 (19 Responses)
Question 2 Comments (20 Responses)
Question 3 (19 Responses)
Question 3 Comments (20 Responses)
Question 4 (19 Responses)
Question 4 Comments (20 Responses)
Question 5 (19 Responses)
Question 5 Comments (20 Responses)
Question 6 (0 Responses)
Question 6 Comments (20 Responses)

Group
Tennessee Valley Authority
Brandy Spraker
Yes
Yes
No
Though the line could be derived from reading the purpose of the standard, it may help avoid potential confusion to the generator owners by specifically excluding generator step-up units from 4.2.1.6 or the second bullet of Attachment B.
No
No
Group
Northeast Power Coordinating Council
Guy Zito
No
The Industry Need statement, as written, implies that the burden of the overlap between PRC-023-3 and PRC-025-1rests with the Generator Owner as the owner of the protection for the elements that connect the generator to the transmission system. The intent of the drafting teams for PRC-023-3 and PRC-025-1 is to segregate the standards so that load-responsive relays used for generator protection are in one standard (PRC-025-1) and load-responsive relays used to protect transmission are in another (PRC-023-3). The Applicability section of PRC 025-1 refers to generator interconnected Facilities which can be construed to mean Generator Owners are responsible for this protection and the terminals at each end. There are Transmission Owners that own protection assets on some, if not all of the terminals for a generator’s interconnection. Terminal responsibility needs clarification. The wording places emphasis on asset ownership.
No

The Reliability Functions table has the Planning Coordinator checked. The Planning Coordinator by definition in the NERC Functional Model is “The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas.” The Planning coordinator does not get involved with generator and transmission relay loadability.
No
The draft SAR and proposed standards PRC-023-3, PRC-025-1 fail to provide a clear distinction as to whether the standard is meant to apply to the owner of a protection system designed to protect transmission elements (which we believe is the intent of PRC-023-3), or the owner of a protection system designed to protect generation elements (which we believe is the intent of PRC-025-1). We believe this was the intent, but the applicability section of either of the proposed standards does not clearly articulate that intent. Suggest the SDT consider an approach similar to that used in PRC-006-1 where the SDT chose to create a ‘standard specific entity’; UFLS entities. Alternatively, the applicability could be modified to more closely match the intent indicated in the Applicability section of the Guideline and Technical Basis document, and in the wording of the Supplemental SAR for Project 2010-13.2 Relay Loadability Order 733 Phase 2 (Relay Loadability: Generation). The standard should be applied to the owner of the particular type of protection system, not applied to a particular function. We are aware of circumstances whereby an entity registered as Transmission Owner owns the protection system that protects for faults on the element(s) owned by an entity registered as a Generator Owner which are solely used to interconnect their generator to the bulk power system. We are also aware of circumstances whereby the Generator Owner owns both the element(s) which are solely used to interconnect their generator to the bulk power system as well as the protection system that protects for faults on those generator interconnection element(s). In both of these, the protection system is designed to protect the bulk power system from the fault, not the generator itself. Changes to proposed PRC 023-2 and PRC 025-1 attempt to establish a bright line, but the functional entity of Generator Owners is still included in PRC 023-3. This results in confusion as to what standard applies for the elements that connect the generator to the BES, as some Transmission Owners own GSU assets. The wording of PRC-025-1, and as stated in the Webinar, imply that “leads assets” will fall under PRC-025-1. There is still confusion in this area so a bright line still has not been established.
No
No
It needs to be made clear that owning the protection systems at the terminals does not imply ownership of the facility. Entities may be responsible for protective relays on each end of a “lead”, but the leads but may be in facilities where one end is owned by a Transmission Owner, and the other end facility is owned by a Generator Owner. The removal of the “Effective Dates” table needs to be re-examined. Among other things, this table included the timelines for meeting PRC-023 on sub-200kV Facilities. If a sub-200kV Facility is identified by the Planning Coordinator, pursuant to Requirement R6, Transmission Owners, Generator Owners, and Distribution Providers must be given a grace period in which to make protection modifications before PRC-023 is applicable to that Facility. PRC-023-2 included a 39-month window for modifying these Facilities once they’ve been identified by the Planning Coordinator. This is an oversight that will cause confusion. In PRC-023-3, in 4.1.2 PRC 023-2 needs to be changed to PRC-023-3.
Group
PacifiCorp
Ryan Millard
Yes
Yes
Yes

No
No
Section 4.1 states that the Transmission Owner, Generator Owner, and Distribution Provider with load-responsive phase protection systems at the terminal of the circuits is responsible for ensuring compliance with PRC-023-3. PacifiCorp maintains that more clarification is needed with respect to who is ultimately responsible for ensuring compliance in instances where the circuit/transmission line has a different owner. Would the owner of the circuit/transmission line rely on the owner of the relays for ensuring compliance?
Group
Luminant
Brenda Hampton
Yes
Yes
Yes
No
No
Group
Southwest Power Pool Standards Development Team
Jonathan Hayes
Yes
Yes
No
While we agree that the revision to PRC023-2 creates a bright line we feel that language should be included in PRC-25-1 to clearly state that the protection relays under PRC023-2 ,or -3 if the SAR is approved, would be not be applicable under PRC025-1.
No
No
Group
ACES Standards Collaborators
Ben Engelby
No
(1) In order to have a clear “bright line,” the generator owner should not apply to PRC-023. Remove all reference to GO from PRC-023, and then the SAR will satisfy the intent of avoiding double

jeopardy.
No
(1) The purpose of the revised SAR is to remove the applicability of GOs for PRC-023-2. Therefore, we recommend unselecting the Generator Owner box in the supplemental SAR, as the revised standard would not apply to GOs.
No
See comments above. There should not be any references to generators in the transmission loadability standard.
No
No
(1) We disagree with including GOs as an applicable entity to PRC-023-2. In order to create a “bright line,” the drafting teams should have separate standards. Have PRC-023 apply to transmission and have PRC-025 apply to generators. It is a simple dividing line. If the team feels that any of the loadability criteria from the transmission loadability standard should be included in PRC-025, then do so, but do not leave any reference to GOs in PRC-023. (2) With the proposed PRC-023-3, there is overlap for GOs. The GO is listed in all six requirements in PRC-023 and in R1 of PRC-025. We recommend removing all references to GOs in PRC-023. If this cannot be accomplished, then update PRC-023-3 to include the aspects of PRC-025 and stop developing a duplicative standard.
Group
Salt River Project
Bob Steiger
Yes
Yes
Yes
No
No
No Comment
Individual
Oliver Burke
Entergy Services, Inc. (Transmission)
Yes
Yes
Yes
No
Yes
Elimination of the table under number 5 of section A in PRC-023-2.
Comments to NERC on Proposed PRC-023-3 Standard It is understood that PRC-023-3 is intended to

replace PRC-023-1 and PRC-023-2 in the near future. The changes proposed for PRC-023-3 in comparison with PRC-023-2 are mainly the removal of the table under number 5 of section A. The table being removed provides the effective dates of the requirements in the PRC-023-2 standard corresponding to the applicable Functional Entities and circuits. Entergy has concerns over the removal of the table as explained below. Our specific area of concern is on the effective date of PRC-023-3 which is defined in the standard as the “first day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities”. (See the bottom of page 1 of the proposed PRC-023-3 standard.) In the Implementation Plan for the proposed PRC-023-3 standard, it is stated that entities applicable to this standard shall be 100% compliant on the effective date of the standard. (See the last line on page 2 of the Implementation Plan.) In other words, the Implementation Plan considers a specific implementation period as not required based on the following two reasons. (See section General Considerations at the bottom of page 1 of the Implementation Plan.) 1. No new entity or facilities are subject to compliance. 2. The implementation plan and period for PRC-023-2 will have been achieved. Entergy sees some scenarios that do not agree with either or both of the above reasons. In such scenarios, the PRC-023-3 effective date and Implementation Plan become problematic. In short, PRC-023-3 proposes to retroactively eliminate the NERC-defined implementation time for ongoing PRC-023-2 compliance activities. A couple of scenarios are provided below for illustration purposes. The first scenario is related to the effective date of requirements R6 and R1 of PRC-023-2. PRC-023-2 became effective in the United States on July 1, 2012. (See the Background section on page 1 of the Implementation Plan for PRC-023-3.) However, PRC-023-2 gives various effective dates that are to be phased in over the period of more than four years. According to the table on pages 2-4 of the PRC-023-2 standard, R6 will become effective on 1/1/2014. For circuits identified by the Planning Coordinator pursuant to Requirement R6, R1 is to be effective 39 months following notification by the Planning Coordinator of their inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B. It means that the applicable entity is given 39 months to develop and implement a plan to bring the applicable circuits to compliance. Therefore, the compliance date can be as late as 4/1/2017 or beyond depending on when the Planning Coordinator will send out its notification on applicable circuits. If PRC-023-3 becomes effective before such date, it will be problematic. For reference, the relevant effective dates for R6 and R1 as specified in PRC-023-2 (Please review Effective Dates as provided in table for NERC Standard PRC-023-2). The second scenario is about new circuits identified by Planning Coordinator during its assessments that are required to be conducted at least once each calendar year pursuant to R6 of PRC-023-3. (See the middle of page 4 of the PRC-023-3 standard.) When new circuits are identified as the result of the yearly assessment, applicable entities will need reasonable amount of time to bring the circuit to compliance. This time period is necessary for budget reasons as well as project planning and construction reasons. While both PRC-023-1 and PRC-023-2 recognize such a need, the proposed standard PRC-023-3 does not. (See section 5.1.3 on page 1 of PRC-023-1 and effective date table on pages 2-4 of PRC-023-2.) Entergy suggests that a 39 months long period of time be given to applicable entities to comply with the PRC-023-3 standard for each facility that is added to the Planning Coordinator’s list. Please review the referenced NERC standard documents. 1) NERC Standard PRC-023-1 2) NERC Standard PRC-023-2 3) NERC Proposed Standard PRC-023-3 (clean) 4) NERC PRC-023-3 Implementation Plan
Individual
Thad Ness
American Electric Power
Yes
Yes
No
AEP believes that the proposed changes in the draft PRC-023-3 create a bright line identifying the scope of PRC-023-3. However, the proposed draft of PRC-025-1 does not create a bright line identifying the scope of PRC-025-1. Load-responsive protective relays installed on the high side terminals of the Generator Step-Up transformer looking towards the Transmission system are clearly in scope for PRC-023-3 but are not clearly excluded from being applicable from PRC-025-1. AEP

recommends including in PRC-025-1 verbiage clearly excluding load-responsive protective relays applicable to PRC-023-3 from PRC-025-1.
No
No
AEP believes there is a typo in PRC-023-3 Section 4.1.2. The statement references PRC-023-2 instead of the current standard revision.
Individual
Ed Croft
Puget Sound Energy
Yes
No
Possibly the GO (section 4.1.2) should be taken out. This function is covered in PRC-025. Taking the GO function out of PRC-023 (and any accompanying items) would further strengthen the brightline between PRC-023-3 and PRC-025-1.
No
see answer to question 2
No
No
Individual
Nazra Gladu
Manitoba Hydro
No
(1) Similar to PRC-025, the phrase “while maintaining reliable protection of the BES” is vague. There are no objective criteria specified for this determination, nor is it clear whether this element will be audited in some fashion. If this element of the requirement cannot be audited, it should be deleted. At a minimum, it should specify that the Responsible Entity makes this determination in its sole discretion.
Yes
No comment.
No
(1) In section 4.1.1, 4.1.2 and 4.1.3, the redlined part “at the terminals of” should be changed to “at the Transmission Owner terminals of”, “at the generator owner terminals of” and “at the Distribution Owner terminals of”. Also, PRC-023-2 in section 4.1.2 should be changed to PRC-023-3.
No
No comment.
No
No comment.
No comment.
Individual
Michael Falvo
Independent Electricity System Operator

Yes
Yes
Yes
No
No
Group
Dominion
Mike Garton
No
Dominion believes the Industry Need as indicated in the SAR could be better stated. We believe the intent of the drafting teams for PRC-023 and PRC-025 is to segregate the standards so that load-responsive relays used for generator protection are in one standard (PRC-025) and load-responsive relays used to protect the bulk power system (Transmission as defined in the NERC Glossary ; An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems.) are in another (PRC-023). The SAR as written appears to infer that, in all cases, the GO owns the protection system that contains the load-responsive relays that protect Transmission (as defined in the NERC Glossary) from faults that occur on the element(s) that make up the Facility used to connect the generator to Transmission. PRC 025 refers to generator interconnected Facilities (ie generator leads..some refer to this as GSU leads) which implies Generator Owners are responsible for this protection and the terminals at each end. There are TOs that own “lead” assets either on both ends or possibly one end of the leads. This is an area that needs further clarification when referring to terminal responsibility. Appears now that wording places emphasis on asset ownership?
No
Under 4.1.2 PRC 023-2 needs to be changed to PRC023-3.
No
The draft SAR and proposed standards PRC-023-3, PRC-025-1 fail to provide a clear distinction as to whether the standard is meant to apply to the owner of a protection system designed to protect transmission elements (which we believe is the intent of PRC-023) or the owner of a protection system designed to protect generation elements (which we believe is the intent of PRC-025). We believe this was the intent of the SDT but we don’t believe the applicability section of either of the proposed standards clearly articulates that intent. We suggest the SDT consider an approach similar to that used in PRC-006-1 where the SDT chose to create a ‘standard specific entity’; UFLS entities. Alternatively, the applicability could be modified to more closely match the intent as indicated in the Applicability section of the Guideline and Technical Basis document and the Supplemental SAR for Project 2010-13.2 Relay Loadability Order 733 Phase 2 (Relay Loadability: Generation). We believe the standard should be applied to the owner of the particular type of protection system, not applied to a particular function. We are aware of circumstances whereby an entity registered as TO owns the protection system that protects for faults on the element(s) owned by an entity registered as a GO which are solely used to interconnect their generator to the bulk power system. We are also aware of circumstances whereby the GO owns both the element(s) which are solely used to interconnect their generator to the bulk power system as well as the protection system that protects for faults on those generator interconnection element(s). In both of these, the protection system is designed to protect the bulk power system from the fault, not the generator itself. Changes to proposed PRC 023-2 and PRC 025-1 attempts to establish a bright line but the functional entity of Generator Owners is still included in PRC 023 so this results in confusion as to what standard applies for the elements that

connect the generator to the BES as some Transmission Owners own GSU assets but the new standard and as stated on the Webinar it implies that “leads assets” will fall under PRC 025. There is still confusion in this area so a bright line still has not been established.
No
No
It needs to be clear that at the terminals does not imply ownership. Entities may be responsible for protective relays on each end of the leads but may be in facilities where one end is owned by a TO and the other end facility is owned by a GO. - The removal of the “Effective Dates” table needs to be reexamined. Among other things, this table included the timelines for meeting PRC-023 on sub-200kV Facilities. If a sub-200kV Facility is identified by the Planning Coordinator, pursuant to Requirement R6, Transmission Owners, Generator Owners, and Distribution Providers must be given a grace period in which to make protection modifications before PRC-023 is applicable to that Facility. PRC-023-2 included a 39-month window for modifying these Facilities once they’ve been identified by the Planning Coordinator. This is an oversight that will cause confusion.
Individual
Timothy Brown
Idaho Power Co.
Yes
Yes
Yes
No
No
There will obviously be additional work to perform the analysis needed to be compliant with the standard. The only business practice that will need to be modified is to perform this analysis for any new or modified generators or generator protective relays to ensure compliance.
Individual
Dale Fredrickson
Wisconsin Electric Power Company
No
Adding this phrase does little to remove the confusion as to applicability to Generator Owners.
No
The applicability of this standard should be removed from the Generator Owner.
No
Any requirements applicable to the Generator Owner should be in a single standard, PRC-025-1. When this standard is approved, Generator Owners that employ load-sensitive relaying on the high-voltage side of the generator step-up transformer, between the GSU and the interconnection with the Transmission system, will be subject to the PRC-025-1 requirements in 3.2.4 for Generator interconnection Facilities, and at that time the PRC-023 standard should have all applicability to Generator Owners removed.
No
No

Individual
Travis Metcalfe
Tacoma Power
No
The phrase “at the terminals of the” does not seem to mitigate the potential overlap between PRC-023 and PRC-025. Should not the distinction be drawn for generation interconnection Facility(ies)? In other words, it seems that transmission lines only connecting generation would be subject to PRC-025-1 and that transmission lines that are part of the more interconnected transmission system would be subject to PRC-023-3. If the Generator Relay Loadability Standard Drafting Team disagrees, additional clarification is requested as to how the phrase “at the terminals of the” mitigates the potential overlap.
Yes
No
The phrase “at the terminals of the” does not seem to mitigate the potential overlap between PRC-023 and PRC-025. Should not the distinction be drawn for generation interconnection Facility(ies)? In other words, it seems that transmission lines only connecting generation would be subject to PRC-025-1 and that transmission lines that are part of the more interconnected transmission system would be subject to PRC-023-3. If the Generator Relay Loadability Standard Drafting Team disagrees, additional clarification is requested as to how the phrase “at the terminals of the” mitigates the potential overlap.
No
No
Group
PPL Corporation NERC Registered Affiliates
Stephen J. Berger
No
The PPL Companies do not agree that addition of the phrase includes the specificity needed to ensure “double jeapordy” for generation. As stated by the North American Generators Forum standards review team: Load-responsive protective relays installed on the high side terminals of the Generator Step-up transformer looking towards the Transmission system appear to be clearly in scope for PRC-23-3 but are not clearly excluded from being applicable to PRC-025-1.
Yes
No
No
No
Individual
Bradley Collard
Oncor Electric Delivery LLC

Oncor is not registered as a Generator Owner, nor does it perform the functions of a Generator Owner. Thus, this question is not applicable to Oncor.
Oncor is not registered as a Generator Owner, nor does it perform the functions of a Generator Owner. Thus, this question is not applicable to Oncor.
Oncor is not registered as a Generator Owner, nor does it perform the functions of a Generator Owner. Thus, this question is not applicable to Oncor.
Oncor is not registered as a Generator Owner, nor does it perform the functions of a Generator Owner. Thus, this question is not applicable to Oncor.
No Comment
The phase-in time for a newly declared critical circuit was removed from the draft PRC-023-3 Effective Dates section; the phase-in time needs to be added back to PRC-023-3. As written in PRC-023-2, R6 requires Planning Coordinators to conduct an assessment of critical circuits on a periodic basis and provide “new circuits” to the appropriate registered entity. The Effective Dates section of PRC-023-2 states a registered entity will have 39 months to comply for newly declared critical circuits following declaration by the Planning Coordinator. This phase-in time period provides necessary time for a registered entity to budget and implement a project to meet PRC-023-2 compliance. The 39 month phase-in period was an acceptable and approved timeframe and should be added back to PRC-023-3.
Group
SERC Protection and Controls Subcommittee
David Greene
Yes
Yes
Yes
No
No
There may be owner issues that impact entity registration.
- It needs to be clear that 'at the terminals' does not imply ownership. Entities may be responsible for protective relays on each end of the leads but may be in facilities where one end is owned by a TO and the other end facility is owned by a GO. - The removal of the “Effective Dates” table needs to be reexamined. Among other things, this table included the timelines for meeting PRC-023 on sub-200kV Facilities. If a sub-200kV Facility is identified by the Planning Coordinator, pursuant to Requirement R6, Transmission Owners, Generator Owners, and Distribution Providers must be given a grace period in which to make protection modifications before PRC-023 is applicable to that Facility. PRC-023-2 included a 39-month window for modifying these Facilities once they’ve been identified by the Planning Coordinator. This is an oversight that will cause confusion. The comments expressed herein(Questions 1-6) represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Group
Bonneville Power Administration
Jamison Dye
No
The difference between “applied to circuits defined in 4.2.1” and “applied at the terminals of the circuits defined in 4.2.1” is not clear. If there is any difference, it is subtle, and probably not worth revising PRC-023-2 for. The bigger problem is that transmission lines over 200kV that attach

generating facilities to the BES seem to be covered by both PRC-023 and PRC-025. PRC-025 applies to Generation interconnection Facilities, but there is no definition of this term. It seems that a 230kV line that connects a GSU transformer to a substation would be considered to be a Generation interconnection facility, and subject to both standards. Therefore, there are two very different requirements that apply to the relays on such a line. A definition of Generator interconnection Facilities is needed, and clarification of which standard the example given above would be covered by is needed.
No
BPA believes there needs to be a clearer delineation between generator facilities and transmission facilities and PRC-023 and PRC-025 written so that there is no overlap between the two. Then the applicability of both PRC-023 and PRC-025 can be easily applied to the owners of the facilities covered by that standard, whether they are registered as a GO, TO, or DP. As PRC-025 is proposed, it only applies to GO's, but what if a TO owns the relays applied to a GSU transformer? These relays would presently not be covered by either PRC-023 or PRC-025.
No
As described in comments 1 and 2, BPA believes there needs to be a definition of "Generator interconnection Facilities" if this term will be used in PRC-025. There needs to be a clear separation between facilities included in PRC-023 and those included in PRC-025, with no overlap. The most likely place for this separation would be at the high-voltage terminal of the GSU transformer, with the GSU and everything between it and the generators included in PRC-025, and the line connecting the GSU to the BES included in PRC-023.
No
No

Consideration of Comments

Project 2010-13.2 – Phase II Relay Loadability SAR for PRC-023-3

The Project 2010-13.2 Drafting Team thanks all commenters who submitted comments on the Standard Authorization Request (SAR) for PRC-023-3. The supplemental SAR was posted for a 45-day public comment period from January 25, 2013 through March 11, 2013. Stakeholders were asked to provide feedback on the SAR and associated documents through a special electronic comment form. There were 20 sets of comments, including comments from approximately 89 different people from approximately 54 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

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

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

Summary Consideration

There were no changes to the posted supplemental SAR in response to comments. Commenters were unclear about the division of responsibilities between the Generator Owner and Transmission Owner. Changes were made to both standards to address these concerns. Please refer to the summary changes to the proposed draft 2 of PRC-023-3 in the Consideration of Comments for draft 2 of PRC-025-1.

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

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Brandy Spraker	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Marjorie Parsons		SERC	6
2.	Tom Vandervort		SERC	5
3.	Annette Dudley		SERC	5
4.	Paul Palmer		SERC	5
5.	Lee Thomas		SERC	5
6.	Daniel McNeely		SERC	1
7.	Wayne Talley		SERC	1

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Carmen Agavriloai	Independent Electricity System Operator	NPCC	2

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

3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	David Kiguel	Hydro One Networks Inc.	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Randy MacDonald	New Brusnwick Power Transmission	NPCC	9
13.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
14.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
15.	Robert Pellegrini	The United Illuminating Company	NPCC	1
16.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
17.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
18.	Brian Robinson	Utility Services	NPCC	8
19.	Brian Shanahan	National Grid	NPCC	1
20.	Wayne Sipperly	New York Power Authority	NPCC	5
21.	Bruce Metruck	New York Power Authority	NPCC	6
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

3.	Group	Brenda Hampton	Luminant						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rick Terrill	Luminant Generation Company LLC	ERCOT	5

4.	Group	Jonathan Hayes	Southwest Power Pool Standards Development Team	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jonathan Hayes	Southwest Power Pool	SPP	NA

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

2. Robert Rhodes	Southwest Power Pool	SPP	NA
3. John Allen	City Utilities of Springfield	SPP	1, 4
4. Chandler Brown	Sunflower Electric	SPP	1
5. Anthony Cassmeyer	Western Farmers Electric Cooperative	SPP	1, 3, 5
6. Gary Condict	Sunflower Electric	SPP	1
7. Karl Diekevers	NPPD	MRO	1, 3, 5
8. Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
9. Valerie Pinamonti	AEP	SPP	1, 3, 5
10. Paul Reynolds	Sunflower Electric	SPP	1
11. Jerry White	Cleco	SPP	1, 3, 5
12. Don Schmit	NPPD	MRO	1, 3, 5
13. Paul Von Hersenberg	Westar Energy	SPP	1, 3, 5, 6
14. Bo Jones	Westar Energy	SPP	1, 3, 5, 6
15. Lynn Schroeder	Westar Energy	SPP	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
5.	Group	Ben Engelby	ACES Standards Collaborators						X				

Additional Member	Additional Organization	Region	Segment Selection
1. Megan Wagner	Sunflower Electric Power Corporation	SPP	1
2. Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
3. Tom Alban	Buckeye Power, Inc.	RFC	3, 4
4. Mark Ringhausen	Old Dominion Electric Cooperative	SERC	3, 4
5. Chris Bradley	Big Rivers Electric Corporation	SERC	
6. Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

				1	2	3	4	5	6	7	8	9	10
6.	Group	Mike Garton	Dominion	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Louis Slade	Dominion Resources Services, Inc.	RFC	5, 6
2. Randi Heise	Dominion Resources Services, Inc.	MRO	5, 6
3. Connie Lowe	Dominion Resources Services, Inc.	NPCC	5, 6
4. Michael Crowley	Virginia Electric and Power Company	SERC	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
7.	Group	Stephen J. Berger	PPL Corporation NERC Registered Affiliates	X		X	X		X				

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda L. Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Brent Ingebrigtson	LG&E and KU Services Company	SERC	3
3.	Annette M. Bannon	PPL Generation, LLC on behalf of its Supply NERC Registered Entities	RFC	5
4.			WECC	5
5.	Elizabeth A. Davis	PPL EnergyPlus, LLC	MRO	6
6.			NPCC	6
7.			SERC	6
8.			SPP	6
9.			RFC	6
10.			WECC	6

8.	Group	David Greene	SERC Protection and Controls Subcommittee										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Nauert	Ameren		
2.	Bridget Coffman	Santee Cooper		
3.	Steve Edwards	Dominion		
4.	Russ Evans	SCE&G		
5.	John Miller	Georga Transmission		
6.	Phil Winston	Southern Co		
7.	David Greene	SERC		

9.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dean Bender	Technical Svcs	WECC	1

10.	Individual	Bob Steiger	Salt River Project	X		X		X	X				
11.	Individual	Ryan Millard	PacifiCorp	X		X		X	X				
12.	Individual	Oliver Burke	Entergy Services, Inc. (Transmission)	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
13.	Individual	Thad Ness	American Electric Power	X		X		X	X				
14.	Individual	Ed Croft	Puget Sound Energy	X		X		X					
15.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
16.	Individual	Michael Falvo	Independent Electricity System Operator		X								
17.	Individual	Timothy Brown	Idaho Power Co.	X									
18.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
19.	Individual	Travis Metcalfe	Tacoma Power	X		X	X	X	X				
20.	Individual	Bradley Collard	Oncor Electric Delivery LLC	X									

1. Do you agree with this scope? If not, please explain.

Summary Consideration:

Commenters were unclear about the division of responsibilities between the Generator Owner and Transmission Owner. Changes were made to both standards to address these concerns. Please refer to the summary changes to the proposed draft 2 of PRC-023-3 in the Consideration of Comments for draft 2 of PRC-025-1.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	The Industry Need statement, as written, implies that the burden of the overlap between PRC-023-3 and PRC-025-1 rests with the Generator Owner as the owner of the protection for the elements that connect the generator to the transmission system. The intent of the drafting teams for PRC-023-3 and PRC-025-1 is to segregate the standards so that load-responsive relays used for generator protection are in one standard (PRC-025-1) and load-responsive relays used to protect transmission are in another (PRC-023-3). The Applicability section of PRC 025-1 refers to generator interconnected Facilities which can be construed to mean Generator Owners are responsible for this protection and the terminals at each end. There are Transmission Owners that own protection assets on some, if not all of the terminals for a generator's interconnection. Terminal responsibility needs clarification. The wording places emphasis on asset ownership.
Response: The drafting team thanks you for your comments. Responsibility is placed on the owner of load-responsive protective relays. The Generator Owner function has been retained in the Applicability of PRC-023-3 to address configurations where the		

Organization	Yes or No	Question 1 Comment
Generator Owner owns load-responsive protective relays on the terminals of network transmission lines. In cases where the Distribution Provider or Transmission Owner owns load-responsive protective relays on the terminals of generator interconnection Facilities such as a generator step-up (GSU) transformer or generator interconnection Facility, the proposed draft 2 of PRC-023-3 Applicability has been revised to address Facilities the Distribution Provider or Transmission Owner may own relative to generating plants. The proposed draft 2 of the PRC-023-3 standard provides the criteria that the Distribution Provider or Transmission Owner shall use to set load-responsive protective relays. Change made to the proposed draft 2 PRC-023-3 standard.		
ACES Standards Collaborators	No	(1) In order to have a clear “bright line,” the generator owner should not apply to PRC-023.Remove all reference to GO from PRC-023, and then the SAR will satisfy the intent of avoiding double jeopardy.
Response: The drafting team thanks you for your comments. Generator Owner function has been retained in the Applicability of PRC-023-3 to address configurations where the Generator Owner owns load-responsive protective relays on the terminals of network transmission lines. In cases where the Distribution Provider or Transmission Owner owns load-responsive protective relays on the terminals of generator interconnection Facilities such as a generator step-up (GSU) transformer or generator interconnection Facility, the proposed draft 2 of PRC-023-3 Applicability has been revised to address Facilities the Distribution Provider or Transmission Owner may own relative to generating plants. The proposed draft 2 of the PRC-023-3 standard provides the criteria that the Distribution Provider or Transmission Owner shall use to set load-responsive protective relays. Change made to the proposed draft 2 PRC-023-3 standard.		
Dominion	No	Dominion believes the Industry Need as indicated in the SAR could be better stated. We believe the intent of the drafting teams for PRC-023 and PRC-025 is to segregate the standards so that load-responsive relays used for generator protection are in one standard (PRC-025) and load-responsive relays used to protect the bulk power system (Transmission as defined in the NERC Glossary; An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is

Organization	Yes or No	Question 1 Comment
		transformed for delivery to customers or is delivered to other electric systems.) are in another (PRC-023). The SAR as written appears to infer that, in all cases, the GO owns the protection system that contains the load-responsive relays that protect Transmission (as defined in the NERC Glossary) from faults that occur on the element(s) that make up the Facility used to connect the generator to Transmission. PRC 025 refers to generator interconnected Facilities (ie generator leads..some refer to this as GSU leads) which implies Generator Owners are responsible for this protection and the terminals at each end. There are TOs that own "lead" assets either on both ends or possibly one end of the leads. This is an area that needs further clarification when referring to terminal responsibility. Appears now that wording places emphasis on asset ownership?
Response: The drafting team thanks you for your comments. Generator Owner function has been retained in the Applicability of PRC-023-3 to address configurations where the Generator Owner owns load-responsive protective relays on the terminals of network transmission lines. In cases where the Distribution Provider or Transmission Owner owns load-responsive protective relays on the terminals of generator interconnection Facilities such as a generator step-up (GSU) transformer or generator interconnection Facility, the proposed draft 2 of PRC-023-3 Applicability has been revised to address Facilities the Distribution Provider or Transmission Owner may own relative to generating plants. The proposed draft 2 of the PRC-023-3 standard provides the criteria that the Distribution Provider or Transmission Owner shall use to set load-responsive protective relays. Change made to the proposed draft 2 PRC-023-3 standard.		
PPL Corporation NERC Registered Affiliates	No	The PPL Companies do not agree that addition of the phrase includes the specificity needed to ensure "double jeapordy" for generation. As stated by the North American Generators Forum standards review

Organization	Yes or No	Question 1 Comment
		team: Load-responsive protective relays installed on the high side terminals of the Generator Step-up transformer looking towards the Transmission system appear to be clearly in scope for PRC-23-3 but are not clearly excluded from being applicable to PRC-025-1.
Response: The drafting team thanks you for your comments. Generator Owner function has been retained in the Applicability of PRC-023-3 to address configurations where the Generator Owner owns load-responsive protective relays on the terminals of network transmission lines. In cases where the Distribution Provider or Transmission Owner owns load-responsive protective relays on the terminals of generator interconnection Facilities such as a generator step-up (GSU) transformer or generator interconnection Facility, the proposed draft 2 of PRC-023-3 Applicability has been revised to address Facilities the Distribution Provider or Transmission Owner may own relative to generating plants. The proposed draft 2 of the PRC-023-3 standard provides the criteria that the Distribution Provider or Transmission Owner shall use to set load-responsive protective relays. Change made to the proposed draft 2 PRC-023-3 standard.		
Bonneville Power Administration	No	The difference between “applied to circuits defined in 4.2.1” and “applied at the terminals of the circuits defined in 4.2.1” is not clear. If there is any difference, it is subtle, and probably not worth revising PRC-023-2 for. The bigger problem is that transmission lines over 200kV that attach generating facilities to the BES seem to be covered by both PRC-023 and PRC-025. PRC-025 applies to Generation interconnection Facilities, but there is no definition of this term. It seems that a 230kV line that connects a GSU transformer to a substation would be considered to be a Generation interconnection facility, and subject to both standards. Therefore, there are two very different requirements that apply to the relays on such a line. A definition of Generator interconnection Facilities is needed, and clarification of which standard the example given above would be covered by is needed.

Organization	Yes or No	Question 1 Comment
Response: The drafting team thanks you for your comments. Generator Owner function has been retained in the Applicability of PRC-023-3 to address configurations where the Generator Owner owns load-responsive protective relays on the terminals of network transmission lines. In cases where the Distribution Provider or Transmission Owner owns load-responsive protective relays on the terminals of generator interconnection Facilities such as a generator step-up (GSU) transformer or generator interconnection Facility, the proposed draft 2 of PRC-023-3 Applicability has been revised to address Facilities the Distribution Provider or Transmission Owner may own relative to generating plants. The proposed draft 2 of the PRC-023-3 standard provides the criteria that the Distribution Provider or Transmission Owner shall use to set load-responsive protective relays. Change made to the proposed draft 2 PRC-023-3 standard.		
Manitoba Hydro	No	(1) Similar to PRC-025, the phrase "while maintaining reliable protection of the BES" is vague. There are no objective criteria specified for this determination, nor is it clear whether this element will be audited in some fashion. If this element of the requirement cannot be audited, it should be deleted. At a minimum, it should specify that the Responsible Entity makes this determination in its sole discretion.
Response: The drafting team agrees. The term, "while maintaining reliable fault protection" describes that the responsible entity is to comply with this standard while achieving their desired protection goals. This phrase is already approved language in PRC-023-2. No change made.		
Wisconsin Electric Power Company	No	Adding this phrase does little to remove the confusion as to applicability to Generator Owners.
Response: The drafting team thanks you for your comments. Generator Owner has been retained in the Applicability of PRC-023-3 to address configurations where the Generator Owner owns load-responsive protective relays on the terminals of network transmission lines. No change made.		
Tacoma Power	No	The phrase "at the terminals of the" does not seem to mitigate the

Organization	Yes or No	Question 1 Comment
		potential overlap between PRC-023 and PRC-025. Should not the distinction be drawn for generation interconnection Facility(ies)? In other words, it seems that transmission lines only connecting generation would be subject to PRC-025-1 and that transmission lines that are part of the more interconnected transmission system would be subject to PRC-023-3. If the Generator Relay Loadability Standard Drafting Team disagrees, additional clarification is requested as to how the phrase "at the terminals of the" mitigates the potential overlap.
Response: The drafting team thanks you for your comments. Generator Owner function has been retained in the Applicability of PRC-023-3 to address configurations where the Generator Owner owns load-responsive protective relays on the terminals of network transmission lines. In cases where the Distribution Provider or Transmission Owner owns load-responsive protective relays on the terminals of generator interconnection Facilities such as a generator step-up (GSU) transformer or generator interconnection Facility, the proposed draft 2 of PRC-023-3 Applicability has been revised to address Facilities the Distribution Provider or Transmission Owner may own relative to generating plants. The proposed draft 2 of the PRC-023-3 standard provides the criteria that the Distribution Provider or Transmission Owner shall use to set load-responsive protective relays. Change made to the proposed draft 2 PRC-023-3 standard.		
Tennessee Valley Authority	Yes	
Luminant	Yes	
Southwest Power Pool Standards Development Team	Yes	
SERC Protection and Controls Subcommittee	Yes	

Organization	Yes or No	Question 1 Comment
PacifiCorp	Yes	
Salt River Project	Yes	
Entergy Services, Inc. (Transmission)	Yes	
American Electric Power	Yes	
Puget Sound Energy	Yes	
Independent Electricity System Operator	Yes	
Idaho Power Co.	Yes	
Oncor Electric Delivery LLC		Oncor is not registered as a Generator Owner, nor does it perform the functions of a Generator Owner. Thus, this question is not applicable to Oncor.
Response: The drafting team thanks you for your participation.		

2. The SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. Do you agree with the list of proposed applicable functional entities? If no, please explain.

Summary Consideration:

Commenters were unclear about the division of responsibilities between the Generator Owner and Transmission Owner. Changes were made to both standards to address these concerns. Please refer to the summary changes to the proposed draft 2 of PRC-023-3 in the Consideration of Comments for draft 2 of PRC-025-1. Typographical errors raised in comments were addressed.

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	The Reliability Functions table has the Planning Coordinator checked. The Planning Coordinator by definition in the NERC Functional Model is "The functional entity that coordinates, facilitates, integrates and evaluates (generally one year and beyond) transmission facility and service plans, and resource plans within a Planning Coordinator area and coordinates those plans with adjoining Planning Coordinator areas." The Planning coordinator does not get involved with generator and transmission relay loadability.
Response: The drafting team thanks you for your comments. PRC-023-3, Requirement R6 assigns the responsibility to the Planning Coordinator. No change made.		
ACES Standards Collaborators	No	(1) The purpose of the revised SAR is to remove the applicability of GOs for PRC-023-2. Therefore, we recommend unselecting the Generator Owner box in the supplemental SAR, as the revised standard would not apply to GOs.
Response: The drafting team thanks you for your comments. Generator Owner has been retained in the Applicability of PRC-023-3 to address configurations where the Generator Owner owns load-responsive protective relays on the terminals of network transmission lines. No change made.		

Organization	Yes or No	Question 2 Comment
Dominion	No	Under 4.1.2 PRC 023-2 needs to be changed to PRC023-3.
Response: The drafting team thanks you for your comments and has corrected the typographical error in the proposed PRC-023-3. Correction made in the proposed PRC-023-3 standard.		
Bonneville Power Administration	No	BPA believes there needs to be a clearer delineation between generator facilities and transmission facilities and PRC-023 and PRC-025 written so that there is no overlap between the two. Then the applicability of both PRC-023 and PRC-025 can be easily applied to the owners of the facilities covered by that standard, whether they are registered as a GO, TO, or DP. As PRC-025 is proposed, it only applies to GO's, but what if a TO owns the relays applied to a GSU transformer? These relays would presently not be covered by either PRC-023 or PRC-025.
Response: The drafting team thanks you for your comments. Generator Owner function has been retained in the Applicability of PRC-023-3 to address configurations where the Generator Owner owns load-responsive protective relays on the terminals of network transmission lines. In cases where the Distribution Provider or Transmission Owner owns load-responsive protective relays on the terminals of generator interconnection Facilities such as a generator step-up (GSU) transformer or generator interconnection Facility, the proposed draft 2 of PRC-023-3 Applicability has been revised to address Facilities the Distribution Provider or Transmission Owner may own relative to generating plants. The proposed draft 2 of the PRC-023-3 standard provides the criteria that the Distribution Provider or Transmission Owner shall use to set load-responsive protective relays. Change made to the proposed draft 2 PRC-023-3 standard.		
Puget Sound Energy	No	Possibly the GO (section 4.1.2) should be taken out. This function is covered in PRC-025. Taking the GO function out of PRC-023 (and any accompanying items) would further strengthen the brightline between PRC-023-3 and PRC-025-1.
Response: The drafting team thanks you for your comments. Generator Owner function has been retained in the Applicability of PRC-023-3 to address configurations where the Generator Owner owns load-responsive protective relays on the terminals of		

Organization	Yes or No	Question 2 Comment
network transmission lines. In cases where the Distribution Provider or Transmission Owner owns load-responsive protective relays on the terminals of generator interconnection Facilities such as a generator step-up (GSU) transformer or generator interconnection Facility, the proposed draft 2 of PRC-023-3 Applicability has been revised to address Facilities the Distribution Provider or Transmission Owner may own relative to generating plants. The proposed draft 2 of the PRC-023-3 standard provides the criteria that the Distribution Provider or Transmission Owner shall use to set load-responsive protective relays. Change made to the proposed draft 2 PRC-023-3 standard.		
Wisconsin Electric Power Company	No	The applicability of this standard should be removed from the Generator Owner.
Response: The drafting team thanks you for your comments. Generator Owner has been retained in the Applicability of PRC-023-3 to address configurations where the Generator Owner owns load-responsive protective relays on the terminals of network transmission lines. No change made.		
Manitoba Hydro	Yes	No comment.
Tennessee Valley Authority	Yes	
Luminant	Yes	
Southwest Power Pool Standards Development Team	Yes	
PPL Corporation NERC Registered Affiliates	Yes	
SERC Protection and Controls Subcommittee	Yes	

Organization	Yes or No	Question 2 Comment
PacifiCorp	Yes	
Salt River Project	Yes	
Entergy Services, Inc. (Transmission)	Yes	
American Electric Power	Yes	
Independent Electricity System Operator	Yes	
Idaho Power Co.	Yes	
Tacoma Power	Yes	
Oncor Electric Delivery LLC		Oncor is not registered as a Generator Owner, nor does it perform the functions of a Generator Owner. Thus, this question is not applicable to Oncor.
Response: The drafting team thanks you for your participation.		

3. Do the proposed changes in the draft PRC-023-3 – Transmission Relay Loadability create the necessary bright line between the draft PRC-025-1 – Generator Relay Loadability create the bright line between the two standards? If no, please explain what would make the bright line clearer.

Summary Consideration:

Commenters were unclear about the division of responsibilities between the Generator Owner and Transmission Owner. Changes were made to both standards to address these concerns. Please refer to the summary changes to the proposed draft 2 of PRC-023-3 in the Consideration of Comments for draft 2 of PRC-025-1. Typographical errors raised in comments were addressed.

Organization	Yes or No	Question 3 Comment
Tennessee Valley Authority	No	Though the line could be derived from reading the purpose of the standard, it may help avoid potential confusion to the generator owners by specifically excluding generator step-up units from 4.2.1.6 or the second bullet of Attachment B.
Response: The drafting team thanks you for your comments. Generator Owner function has been retained in the Applicability of PRC-023-3 to address configurations where the Generator Owner owns load-responsive protective relays on the terminals of network transmission lines. In cases where the Distribution Provider or Transmission Owner owns load-responsive protective relays on the terminals of generator interconnection Facilities such as a generator step-up (GSU) transformer or generator interconnection Facility, the proposed draft 2 of PRC-023-3 Applicability has been revised to address Facilities the Distribution Provider or Transmission Owner may own relative to generating plants. The proposed draft 2 of the PRC-023-3 standard provides the criteria that the Distribution Provider or Transmission Owner shall use to set load-responsive protective relays. Change made to the proposed draft 2 PRC-023-3 standard.		
Northeast Power Coordinating Council	No	The draft SAR and proposed standards PRC-023-3, PRC-025-1 fail to provide a clear distinction as to whether the standard is meant to apply to the owner of a protection system designed to protect transmission elements (which we believe is

Organization	Yes or No	Question 3 Comment
		the intent of PRC-023-3), or the owner of a protection system designed to protect generation elements (which we believe is the intent of PRC-025-1). We believe this was the intent, but the applicability section of either of the proposed standards does not clearly articulate that intent. Suggest the SDT consider an approach similar to that used in PRC-006-1 where the SDT chose to create a 'standard specific entity'; UFLS entities. Alternatively, the applicability could be modified to more closely match the intent indicated in the Applicability section of the Guideline and Technical Basis document, and in the wording of the Supplemental SAR for Project 2010-13.2 Relay Loadability Order 733 Phase 2 (Relay Loadability: Generation). The standard should be applied to the owner of the particular type of protection system, not applied to a particular function. We are aware of circumstances whereby an entity registered as Transmission Owner owns the protection system that protects for faults on the element(s) owned by an entity registered as a Generator Owner which are solely used to interconnect their generator to the bulk power system. We are also aware of circumstances whereby the Generator Owner owns both the element(s) which are solely used to interconnect their generator to the bulk power system as well as the protection system that protects for faults on those generator interconnection element(s). In both of these, the protection system is designed to protect the bulk power system from the fault, not the generator itself. Changes to proposed PRC 023-2 and PRC 025-1 attempt to establish a bright line, but the functional entity of Generator Owners is still included in PRC 023-3. This results in confusion as to what standard applies for the elements that connect the generator to the BES, as some Transmission Owners own GSU assets. The wording of PRC-025-1, and as

Organization	Yes or No	Question 3 Comment
		stated in the Webinar, imply that "leads assets" will fall under PRC-025-1. There is still confusion in this area so a bright line still has not been established.
Response: The drafting team thanks you for your comments. Generator Owner function has been retained in the Applicability of PRC-023-3 to address configurations where the Generator Owner owns load-responsive protective relays on the terminals of network transmission lines. In cases where the Distribution Provider or Transmission Owner owns load-responsive protective relays on the terminals of generator interconnection Facilities such as a generator step-up (GSU) transformer or generator interconnection Facility, the proposed draft 2 of PRC-023-3 Applicability has been revised to address Facilities the Distribution Provider or Transmission Owner may own relative to generating plants. The proposed draft 2 of the PRC-023-3 standard provides the criteria that the Distribution Provider or Transmission Owner shall use to set load-responsive protective relays. Change made to the proposed draft 2 PRC-023-3 standard.		
Southwest Power Pool Standards Development Team	No	While we agree that the revision to PRC023-2 creates a bright line we feel that language should be included in PRC-25-1 to clearly state that the protection relays under PRC023-2 ,or -3 if the SAR is approved, would be not be applicable under PRC025-1.
Response: The drafting team thanks you for your comments. Generator Owner function has been retained in the Applicability of PRC-023-3 to address configurations where the Generator Owner owns load-responsive protective relays on the terminals of network transmission lines. In cases where the Distribution Provider or Transmission Owner owns load-responsive protective relays on the terminals of generator interconnection Facilities such as a generator step-up (GSU) transformer or generator interconnection Facility, the proposed draft 2 of PRC-023-3 Applicability has been revised to address Facilities the Distribution Provider or Transmission Owner may own relative to generating plants. The proposed draft 2 of the PRC-023-3 standard provides the criteria that the Distribution Provider or Transmission Owner shall use to set load-responsive protective relays. Change made to the proposed draft 2 PRC-023-3 standard.		
ACES Standards Collaborators	No	See comments above. There should not be any references to generators in the transmission loadability standard.

Organization	Yes or No	Question 3 Comment
Response: The drafting team thanks you for your comments. Generator Owner function has been retained in the Applicability of PRC-023-3 to address configurations where the Generator Owner owns load-responsive protective relays on the terminals of network transmission lines. In cases where the Distribution Provider or Transmission Owner owns load-responsive protective relays on the terminals of generator interconnection Facilities such as a generator step-up (GSU) transformer or generator interconnection Facility, the proposed draft 2 of PRC-023-3 Applicability has been revised to address Facilities the Distribution Provider or Transmission Owner may own relative to generating plants. The proposed draft 2 of the PRC-023-3 standard provides the criteria that the Distribution Provider or Transmission Owner shall use to set load-responsive protective relays. Change made to the proposed draft 2 PRC-023-3 standard.		
Dominion	No	The draft SAR and proposed standards PRC-023-3, PRC-025-1 fail to provide a clear distinction as to whether the standard is meant to apply to the owner of a protection system designed to protect transmission elements (which we believe is the intent of PRC-023) or the owner of a protection system designed to protect generation elements (which we believe is the intent of PRC-025). We believe this was the intent of the SDT but we don't believe the applicability section of either of the proposed standards clearly articulates that intent. We suggest the SDT consider an approach similar to that used in PRC-006-1 where the SDT chose to create a 'standard specific entity'; UFLS entities. Alternatively, the applicability could be modified to more closely match the intent as indicated in the Applicability section of the Guideline and Technical Basis document and the Supplemental SAR for Project 2010-13.2 Relay Loadability Order 733 Phase 2 (Relay Loadability: Generation). We believe the standard should be applied to the owner of the particular type of protection system, not applied to a particular function. We are aware of circumstances whereby an entity registered as TO owns the protection system that protects for faults on the element(s) owned by an entity registered as a GO which are solely used to interconnect their generator to the

Organization	Yes or No	Question 3 Comment
		bulk power system. We are also aware of circumstances whereby the GO owns both the element(s) which are solely used to interconnect their generator to the bulk power system as well as the protection system that protects for faults on those generator interconnection element(s). In both of these, the protection system is designed to protect the bulk power system from the fault, not the generator itself. Changes to proposed PRC 023-2 and PRC 025-1 attempts to establish a bright line but the functional entity of Generator Owners is still included in PRC 023 so this results in confusion as to what standard applies for the elements that connect the generator to the BES as some Transmission Owners own GSU assets but the new standard and as stated on the Webinar it implies that “leads assets” will fall under PRC 025. There is still confusion in this area so a bright line still has not been established.
Response: The drafting team thanks you for your comments. Generator Owner function has been retained in the Applicability of PRC-023-3 to address configurations where the Generator Owner owns load-responsive protective relays on the terminals of network transmission lines. In cases where the Distribution Provider or Transmission Owner owns load-responsive protective relays on the terminals of generator interconnection Facilities such as a generator step-up (GSU) transformer or generator interconnection Facility, the proposed draft 2 of PRC-023-3 Applicability has been revised to address Facilities the Distribution Provider or Transmission Owner may own relative to generating plants. The proposed draft 2 of the PRC-023-3 standard provides the criteria that the Distribution Provider or Transmission Owner shall use to set load-responsive protective relays. Change made to the proposed draft 2 PRC-023-3 standard.		
Bonneville Power Administration	No	As described in comments 1 and 2, BPA believes there needs to be a definition of “Generator interconnection Facilities” if this term will be used in PRC-025. There needs to be a clear separation between facilities included in PRC-023 and those included in PRC-025, with no overlap.

Organization	Yes or No	Question 3 Comment
		The most likely place for this separation would be at the high-voltage terminal of the GSU transformer, with the GSU and everything between it and the generators included in PRC-025, and the line connecting the GSU to the BES included in PRC-023.
Response: The drafting team thanks you for your comments. Generator Owner function has been retained in the Applicability of PRC-023-3 to address configurations where the Generator Owner owns load-responsive protective relays on the terminals of network transmission lines. In cases where the Distribution Provider or Transmission Owner owns load-responsive protective relays on the terminals of generator interconnection Facilities such as a generator step-up (GSU) transformer or generator interconnection Facility, the proposed draft 2 of PRC-023-3 Applicability has been revised to address Facilities the Distribution Provider or Transmission Owner may own relative to generating plants. The proposed draft 2 of the PRC-023-3 standard provides the criteria that the Distribution Provider or Transmission Owner shall use to set load-responsive protective relays. Change made to the proposed draft 2 PRC-023-3 standard.		
American Electric Power	No	AEP believes that the proposed changes in the draft PRC-023-3 create a bright line identifying the scope of PRC-023-3. However, the proposed draft of PRC-025-1 does not create a bright line identifying the scope of PRC-025-1. Load-responsive protective relays installed on the high side terminals of the Generator Step-Up transformer looking towards the Transmission system are clearly in scope for PRC-023-3 but are not clearly excluded from being applicable from PRC-025-1. AEP recommends including in PRC-025-1 verbiage clearly excluding load-responsive protective relays applicable to PRC-023-3 from PRC-025-1.
Response: The drafting team thanks you for your comments. Generator Owner function has been retained in the Applicability of PRC-023-3 to address configurations where the Generator Owner owns load-responsive protective relays on the terminals of network transmission lines. In cases where the Distribution Provider or Transmission Owner owns load-responsive protective relays on the terminals of generator interconnection Facilities such as a generator step-up (GSU) transformer or generator		

Organization	Yes or No	Question 3 Comment
interconnection Facility, the proposed draft 2 of PRC-023-3 Applicability has been revised to address Facilities the Distribution Provider or Transmission Owner may own relative to generating plants. The proposed draft 2 of the PRC-023-3 standard provides the criteria that the Distribution Provider or Transmission Owner shall use to set load-responsive protective relays. Change made to the proposed draft 2 PRC-023-3 standard.		
Puget Sound Energy	No	see answer to question 2
Response: The drafting team thanks you for your comments; please refer to the above response(s) in question 2.		
Manitoba Hydro	No	(1) In section 4.1.1, 4.1.2 and 4.1.3, the redlined part "at the terminals of" should be changed to "at the Transmission Owner terminals of", "at the generator owner terminals of" and "at the Distribution Owner terminals of". Also, PRC-023-2 in section 4.1.2 should be changed to PRC-023-3.
Response: The drafting team has included additional explanation in the PRC-025-1 Guidelines and Technical Basis document and made several changes to both drafts of PRC-023-3 and PRC-025-1 to address these concerns and has corrected the typographical error from version -2 to version -3. Correction made to the proposed PRC-023-3 standard.		
Wisconsin Electric Power Company	No	Any requirements applicable to the Generator Owner should be in a single standard, PRC-025-1. When this standard is approved, Generator Owners that employ load-sensitive relaying on the high-voltage side of the generator step-up transformer, between the GSU and the interconnection with the Transmission system, will be subject to the PRC-025-1 requirements in 3.2.4 for Generator interconnection Facilities, and at that time the PRC-023 standard should have all applicability to Generator Owners removed.
Response: The drafting team thanks you for your comments. Generator Owner function has been retained in the Applicability of PRC-023-3 to address configurations where the Generator Owner owns load-responsive protective relays on the terminals of network transmission lines. In cases where the Distribution Provider or Transmission Owner owns load-responsive protective		

Organization	Yes or No	Question 3 Comment
relays on the terminals of generator interconnection Facilities such as a generator step-up (GSU) transformer or generator interconnection Facility, the proposed draft 2 of PRC-023-3 Applicability has been revised to address Facilities the Distribution Provider or Transmission Owner may own relative to generating plants. The proposed draft 2 of the PRC-023-3 standard provides the criteria that the Distribution Provider or Transmission Owner shall use to set load-responsive protective relays. Change made to the proposed draft 2 PRC-023-3 standard.		
Tacoma Power	No	The phrase "at the terminals of the" does not seem to mitigate the potential overlap between PRC-023 and PRC-025. Should not the distinction be drawn for generation interconnection Facility(ies)? In other words, it seems that transmission lines only connecting generation would be subject to PRC-025-1 and that transmission lines that are part of the more interconnected transmission system would be subject to PRC-023-3. If the Generator Relay Loadability Standard Drafting Team disagrees, additional clarification is requested as to how the phrase "at the terminals of the" mitigates the potential overlap.
Response: The drafting team thanks you for your comments. Generator Owner function has been retained in the Applicability of PRC-023-3 to address configurations where the Generator Owner owns load-responsive protective relays on the terminals of network transmission lines. In cases where the Distribution Provider or Transmission Owner owns load-responsive protective relays on the terminals of generator interconnection Facilities such as a generator step-up (GSU) transformer or generator interconnection Facility, the proposed draft 2 of PRC-023-3 Applicability has been revised to address Facilities the Distribution Provider or Transmission Owner may own relative to generating plants. The proposed draft 2 of the PRC-023-3 standard provides the criteria that the Distribution Provider or Transmission Owner shall use to set load-responsive protective relays. Change made to the proposed draft 2 PRC-023-3 standard.		
PPL Corporation NERC Registered Affiliates	No	
Luminant	Yes	

Organization	Yes or No	Question 3 Comment
SERC Protection and Controls Subcommittee	Yes	
PacifiCorp	Yes	
Salt River Project	Yes	
Entergy Services, Inc. (Transmission)	Yes	
Independent Electricity System Operator	Yes	
Idaho Power Co.	Yes	
Oncor Electric Delivery LLC		Oncor is not registered as a Generator Owner, nor does it perform the functions of a Generator Owner. Thus, this question is not applicable to Oncor.
Response: The drafting team thanks you for your participation.		

4. Are you aware of any regional variances that will be needed as a result of this project? If yes, please identify the regional variance.

Summary Consideration:

No regional variances were identified.

Organization	Yes or No	Question 4 Comment
Manitoba Hydro	No	No comment.
Tennessee Valley Authority	No	
Northeast Power Coordinating Council	No	
Luminant	No	
Southwest Power Pool Standards Development Team	No	
ACES Standards Collaborators	No	
Dominion	No	
PPL Corporation NERC Registered Affiliates	No	
SERC Protection and Controls Subcommittee	No	

Organization	Yes or No	Question 4 Comment
Bonneville Power Administration	No	
PacifiCorp	No	
Salt River Project	No	
Entergy Services, Inc. (Transmission)	No	
American Electric Power	No	
Puget Sound Energy	No	
Independent Electricity System Operator	No	
Idaho Power Co.	No	
Wisconsin Electric Power Company	No	
Tacoma Power	No	
Oncor Electric Delivery LLC		Oncor is not registered as a Generator Owner, nor does it perform the functions of a Generator Owner. Thus, this question is not applicable to Oncor.
Response: The drafting team thanks you for your participation.		

5. Are you aware of any business practice that will be needed or that will need to be modified as a result of this project? If yes, please identify the business practice.

Summary Consideration:

Commenters were unclear about the division of responsibilities between the Generator Owner and Transmission Owner. Changes were made to both standards to address these concerns. Please refer to the summary changes to the proposed draft 2 of PRC-023-3 in the Consideration of Comments for draft 2 of PRC-025-1. Typographical errors raised in comments were addressed including the re-inserting the Implementation Plan for the proposed PRC-023-3.

Organization	Yes or No	Question 5 Comment
SERC Protection and Controls Subcommittee	No	There may be owner issues that impact entity registration.
Response: The drafting team thanks you for your comments. Generator Owner function has been retained in the Applicability of PRC-023-3 to address configurations where the Generator Owner owns load-responsive protective relays on the terminals of network transmission lines. In cases where the Distribution Provider or Transmission Owner owns load-responsive protective relays on the terminals of generator interconnection Facilities such as a generator step-up (GSU) transformer or generator interconnection Facility, the proposed draft 2 of PRC-023-3 Applicability has been revised to address Facilities the Distribution Provider or Transmission Owner may own relative to generating plants. The proposed draft 2 of the PRC-023-3 standard provides the criteria that the Distribution Provider or Transmission Owner shall use to set load-responsive protective relays. Change made to the proposed draft 2 PRC-023-3 standard.		
Manitoba Hydro	No	No comment.
Idaho Power Co.	No	There will obviously be additional work to perform the analysis needed to be compliant with the standard. The only business practice that will need to be modified is to perform this analysis for any new or modified generators or

Organization	Yes or No	Question 5 Comment
		generator protective relays to ensure compliance.
Response: The drafting team thanks you for your comment.		
Tennessee Valley Authority	No	
Northeast Power Coordinating Council	No	
Luminant	No	
Southwest Power Pool Standards Development Team	No	
ACES Standards Collaborators	No	
Dominion	No	
PPL Corporation NERC Registered Affiliates	No	
Bonneville Power Administration	No	
PacifiCorp	No	
Salt River Project	No	
American Electric Power	No	

Organization	Yes or No	Question 5 Comment
Puget Sound Energy	No	
Independent Electricity System Operator	No	
Wisconsin Electric Power Company	No	
Tacoma Power	No	
Entergy Services, Inc. (Transmission)	Yes	Elimination of the table under number 5 of section A in PRC-023-2.
Response: The drafting team thanks you for your comments and has re-inserted the Implementation Plan information under the proposed draft 2 of the PRC-023-3 standard, Section A, Item 5. Change made to the Implementation Plan.		
Oncor Electric Delivery LLC		No Comment

6. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:

Summary Consideration:

Commenters were unclear about the division of responsibilities between the Generator Owner and Transmission Owner. Changes were made to both standards to address these concerns. Please refer to the summary changes to the proposed draft 2 of PRC-023-3 in the Consideration of Comments for draft 2 of PRC-025-1. Typographical errors raised in comments were addressed including the re-inserting the Implementation Plan for the proposed PRC-023-3.

Organization	Yes or No	Question 6 Comment
SERC Protection and Controls Subcommittee		- It needs to be clear that 'at the terminals' does not imply ownership. Entities may be responsible for protective relays on each end of the leads but may be in facilities where one end is owned by a TO and the other end facility is owned by a GO. **Response:** The drafting team agrees and the proposed PRC-023-3 standard makes this distinction clear. No change made. - The removal of the "Effective Dates" table needs to be reexamined. Among other things, this table included the timelines for meeting PRC-023 on sub-200kV Facilities. If a sub-200kV Facility is identified by the Planning Coordinator, pursuant to Requirement R6, Transmission Owners, Generator Owners, and Distribution Providers must be given a grace period in which to make protection modifications before PRC-023 is applicable to that Facility. PRC-023-2 included a 39-month window for modifying these Facilities once they've been identified by the Planning Coordinator. This is an oversight that will cause confusion. **Response:** The drafting team thanks you for your comments and has re-inserted the implementation plan information under the proposed draft 2 of the PRC-023-3

Organization	Yes or No	Question 6 Comment
		standard, Section A, Item 5. Change made to the proposed PRC-023-3 Implementation Plan. The comments expressed herein (Questions 1-6) represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Response: The drafting team thanks you for your comments; please refer to the above response(s).		
ACES Standards Collaborators		(1) We disagree with including GOs as an applicable entity to PRC-023-2. In order to create a “bright line,” the drafting teams should have separate standards. Have PRC-023 apply to transmission and have PRC-025 apply to generators. It is a simple dividing line. If the team feels that any of the loadability criteria from the transmission loadability standard should be included in PRC-025, then do so, but do not leave any reference to GOs in PRC-023. (2) With the proposed PRC-023-3, there is overlap for GOs. The GO is listed in all six requirements in PRC-023 and in R1 of PRC-025. We recommend removing all references to GOs in PRC-023.If this cannot be accomplished, then update PRC-023-3 to include the aspects of PRC-025 and stop developing a duplicative standard.
Response: The drafting team thanks you for your comments. Generator Owner function has been retained in the Applicability of PRC-023-3 to address configurations where the Generator Owner owns load-responsive protective relays on the terminals of network transmission lines. In cases where the Distribution Provider or Transmission Owner owns load-responsive protective relays on the terminals of generator interconnection Facilities such as a generator step-up (GSU) transformer or generator interconnection Facility, the proposed draft 2 of PRC-023-3 Applicability has been revised to address Facilities the Distribution Provider or Transmission Owner may own relative to generating plants. The proposed draft 2 of the PRC-023-3 standard provides the criteria that the Distribution Provider or Transmission Owner shall use to set load-responsive protective relays. Change made to the proposed draft 2		

Organization	Yes or No	Question 6 Comment
PRC-023-3 standard.		
American Electric Power		AEP believes there is a typo in PRC-023-3 Section 4.1.2. The statement references PRC-023-2 instead of the current standard revision.
Response: The drafting team thanks you for your comment and has corrected the typographical error from version -2 to version -3. Correction made to the proposed PRC-023-3 standard.		
Entergy Services, Inc. (Transmission)		Comments to NERC on Proposed PRC-023-3 Standard It is understood that PRC-023-3 is intended to replace PRC-023-1 and PRC-023-2 in the near future. The changes proposed for PRC-023-3 in comparison with PRC-023-2 are mainly the removal of the table under number 5 of section A. The table being removed provides the effective dates of the requirements in the PRC-023-2 standard corresponding to the applicable Functional Entities and circuits. Entergy has concerns over the removal of the table as explained below. Our specific area of concern is on the effective date of PRC-023-3 which is defined in the standard as the "first day of the first calendar quarter beyond the date that this standard is approved by applicable regulatory authorities". (See the bottom of page 1 of the proposed PRC-023-3 standard.) In the Implementation Plan for the proposed PRC-023-3 standard, it is stated that entities applicable to this standard shall be 100% compliant on the effective date of the standard. (See the last line on page 2 of the Implementation Plan.) In other words, the Implementation Plan considers a specific implementation period as not required based on the following two reasons. (See section General Considerations at the bottom of page 1 of the Implementation Plan.) 1. No new entity or facilities are subject to compliance.

Organization	Yes or No	Question 6 Comment
		2. The implementation plan and period for PRC-023-2 will have been achieved. Entergy sees some scenarios that do not agree with either or both of the above reasons. In such scenarios, the PRC-023-3 effective date and Implementation Plan become problematic. In short, PRC-023-3 proposes to retroactively eliminate the NERC-defined implementation time for ongoing PRC-023-2 compliance activities. A couple of scenarios are provided below for illustration purposes. The first scenario is related to the effective date of requirements R6 and R1 of PRC-023-2. PRC-023-2 became effective in the United States on July 1, 2012. (See the Background section on page 1 of the Implementation Plan for PRC-023-3.) However, PRC-023-2 gives various effective dates that are to be phased in over the period of more than four years. According to the table on pages 2-4 of the PRC-023-2 standard, R6 will become effective on 1/1/2014. For circuits identified by the Planning Coordinator pursuant to Requirement R6, R1 is to be effective 39 months following notification by the Planning Coordinator of their inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B. It means that the applicable entity is given 39 months to develop and implement a plan to bring the applicable circuits to compliance. Therefore, the compliance date can be as late as 4/1/2017 or beyond depending on when the Planning Coordinator will send out its notification on applicable circuits. If PRC-023-3 becomes effective before such date, it will be problematic. For reference, the relevant effective dates for R6 and R1 as specified in PRC-023-2(Please review Effective Dates as provided in table for NERC Standard PRC-023-2). The second scenario is about new circuits identified by Planning Coordinator during its assessments that are required to be conducted at least once each calendar year pursuant to R6 of PRC-023-3. (See the middle of page 4 of the PRC-023-3 standard.) When new circuits are identified as the result of the yearly assessment, applicable

Organization	Yes or No	Question 6 Comment
		entities will need reasonable amount of time to bring the circuit to compliance. This time period is necessary for budget reasons as well as project planning and construction reasons. While both PRC-023-1 and PRC-023-2 recognize such a need, the proposed standard PRC-023-3 does not. (See section 5.1.3 on page 1 of PRC-023-1 and effective date table on pages 2-4 of PRC-023-2.) Entergy suggests that a 39 months long period of time be given to applicable entities to comply with the PRC-023-3 standard for each facility that is added to the Planning Coordinator's list. Please review the referenced NERC standard documents. 1) NERC Standard PRC-023-1 2) NERC Standard PRC-023-2 3) NERC Proposed Standard PRC-023-3 (clean) 4) NERC PRC-023-3 Implementation Plan
Response: The drafting team thanks you for your comments and has re-inserted the implementation plan information under the proposed draft 2 of the PRC-023-3 standard, Section A, Item 5. Change made to the proposed PRC-023-3 Implementation Plan.		
Dominion		It needs to be clear that at the terminals does not imply ownership. Entities may be responsible for protective relays on each end of the leads but may be in facilities where one end is owned by a TO and the other end facility is owned by a GO. **Response:** The drafting team agrees and the proposed PRC-023-3 standard makes this distinction clear. No change made. -The removal of the "Effective Dates" table needs to be reexamined. Among other things, this table included the timelines for meeting PRC-023 on sub-200kV Facilities. If a sub-200kV Facility is identified by the Planning Coordinator, pursuant to Requirement R6, Transmission Owners, Generator Owners, and Distribution Providers must be given a grace period in which to make protection modifications

Organization	Yes or No	Question 6 Comment
		before PRC-023 is applicable to that Facility. PRC-023-2 included a 39-month window for modifying these Facilities once they've been identified by the Planning Coordinator. This is an oversight that will cause confusion. **Response:** The drafting team thanks you for your comments and has re-inserted the implementation plan information under the proposed draft 2 of the PRC-023-3 standard, Section A, Item 5. Change made to the propose PRC-023-3 Implementation Plan.
Response: The drafting team thanks you for your comments; please refer to the above response(s).		
Northeast Power Coordinating Council		It needs to be made clear that owning the protection systems at the terminals does not imply ownership of the facility. Entities may be responsible for protective relays on each end of a "lead", but the leads but may be in facilities where one end is owned by a Transmission Owner, and the other end facility is owned by a Generator Owner. **Response:** The drafting team agrees and the proposed PRC-023-3 standard makes this distinction clear. No change made. The removal of the "Effective Dates" table needs to be re-examined. Among other things, this table included the timelines for meeting PRC-023 on sub-200kV Facilities. If a sub-200kV Facility is identified by the Planning Coordinator, pursuant to Requirement R6, Transmission Owners, Generator Owners, and Distribution Providers must be given a grace period in which to make protection modifications before PRC-023 is applicable to that Facility. PRC-023-2 included a 39-month window for modifying these Facilities once they've been identified by the Planning Coordinator. This is an oversight that will cause confusion. **Response:** The drafting team thanks you for your comments and has re-inserted the implementation plan information under the proposed draft 2 of the PRC-023-3

Organization	Yes or No	Question 6 Comment
		standard, Section A, Item 5. Change made to the proposed PRC-023-3 Implementation Plan. In PRC-023-3, in 4.1.2 PRC 023-2 needs to be changed to PRC-023-3. **Response:** The drafting team thanks you for your comment and has corrected the typographical error from version -2 to version -3. Correction made to the proposed PRC-023-3 standard.
Response: The drafting team thanks you for your comments; please refer to the above response(s).		
Salt River Project		No Comment
Manitoba Hydro		No comment.
PacifiCorp		Section 4.1 states that the Transmission Owner, Generator Owner, and Distribution Provider with load-responsive phase protection systems at the terminal of the circuits is responsible for ensuring compliance with PRC-023-3. PacifiCorp maintains that more clarification is needed with respect to who is ultimately responsible for ensuring compliance in instances where the circuit/transmission line has a different owner. Would the owner of the circuit/transmission line rely on the owner of the relays for ensuring compliance?
Response: The drafting team agrees and the proposed PRC-023-3 standard makes this distinction clear. The proposed PRC-023-3 standard (and proposed PRC-025-1) is based on ownership of the load-responsive protective relay, not the owner of the terminal or line. No change made.		
Oncor Electric Delivery LLC		The phase-in time for a newly declared critical circuit was removed from the draft PRC-023-3 Effective Dates section; the phase-in time needs to be added back to PRC-023-3. As written in PRC-023-2, R6 requires Planning Coordinators to conduct an

Organization	Yes or No	Question 6 Comment
		assessment of critical circuits on a periodic basis and provide “new circuits” to the appropriate registered entity. The Effective Dates section of PRC-023-2 states a registered entity will have 39 months to comply for newly declared critical circuits following declaration by the Planning Coordinator. This phase-in time period provides necessary time for a registered entity to budget and implement a project to meet PRC-023-2 compliance. The 39 month phase-in period was an acceptable and approved timeframe and should be added back to PRC-023-3.
Response: The drafting team thanks you for your comment and has re-inserted the Implementation Plan information under the proposed draft 2 of the PRC-023-3 standard, Section A, Item 5. Change made to the proposed PRC-023-3 Implementation Plan.		

END OF REPORT

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. The Standards Committee approved the Supplemental SAR regarding PRC-023-2 for posting on January 16-17, 2013.
2. The Supplemental SAR was posted for formal comment on January 25, 2013.

Description of Current Draft

The Generator Relay Loadability Standard Drafting Team (GENRLOSDT) is posting Draft 1 of PRC-023-3 – Transmission Relay Loadability for a 30-day formal comment period.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	April 2013
45-day Formal Comment Period and Initial Ballot	August 2013
10-day Recirculation Ballot	October 2013
BOT adoption	November 2013
File with FERC	December 2013

Effective Dates

See PRC-023-3 Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision

Version	Date	Action	Change Tracking
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	TBD	Clarify applicability for consistency with PRC-025-1 and other minor corrections	Supplemental SAR (Project 2010-13.2)

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.

No new or revised term is being proposed.

A. Introduction

1. **Title: Transmission Relay Loadability**
2. **Number:** PRC-023-3
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. Functional Entity

4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1, 4.2.3, or 4.2.4 *(Circuits Subject to Requirements R1 – R5, R7, and R8)*.

4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1, 4.2.3, or 4.2.4 *(Circuits Subject to Requirements R1 – R5, R7, and R8)*, provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinator

4.2. Circuits

4.2.1 Circuits Subject to Requirements R1 – R5

4.2.1.1 Transmission lines operated at 200 kV and above.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

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

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

4.2.2 Circuits Subject to Requirement R6

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES

4.2.3 Circuits Subject to Requirement R7

4.2.3.1 Transmission lines that are used solely to export energy directly from a BES generating unit or generating plant to the network.

4.2.4 Circuits Subject to Requirement R8

4.2.4.1 Transformers with low voltage terminals connected below 200 kV, including generator step-up transformers, that are used solely to export energy directly from a BES generating unit or generating plant to the network.

5. **Effective Dates:** See Implementation Plan

.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. 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] [Time Horizon: Long Term Planning]*.

Criteria:

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).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).
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:
   - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
   - 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.
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 Requirement R1, criterion 3, using the full line inductive reactance.
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).
6. Not used.

[1] 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.

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.

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.

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.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays 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

10.1 Set load responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 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, for at least 15 minutes to provide time 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 set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

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:

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

b. 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.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

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[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration,* Clause 4.4, Figure 4

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

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. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 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]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-3 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-3, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

R7. Each Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator interconnection Facility. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*.

R8. Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator step-up transformer. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe.

M7. Each Transmission Owner and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) to show that each of its generator interconnection Facility relays is set according to one of the criteria in Attachment C. (R7)

M8. Each Transmission Owner and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) to show that each of its generator step-up transformer relays is set according to one of the criteria in Attachment C. (R8)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

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

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5, R7, and R8 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per R6.

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

The Compliance Enforcement Authority shall keep the last audit record 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.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 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. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated.	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must

Requirement	Lower	Moderate	High	Severe
		(part 6.2)		comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.
R7	N/A	N/A	N/A	The responsible entity did not set one of its generator interconnection Facility relays in accordance with the criteria in Attachment C.
R8	N/A	N/A	N/A	The responsible entity did not set one of its generator step-up transformer relays in accordance with the criteria in Attachment C.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. 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, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

PRC-023-3 — 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).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

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

2.1. 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 except as noted in section 1.6

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

2.4. Protective relays applied at the terminals of generation Facilities in accordance with NERC Reliability Standard PRC-025-1 or its successor(s).

2.5. Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-3 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is a monitored Facility of an IROL, where the IROL was determined in the planning horizon pursuant to FAC-010.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

PRC-023-3 — Attachment C

The following criteria shall be used to set load-responsive relays on generator interconnection Facilities and generator-step-up transformers.

This standard does not require the responsible entity to use any of the protective functions listed in Table 1. Each responsible entity that applies load-responsive protective relays on Facilities listed in 4.2.3 and 4.2.4, Facilities shall use one of the following Options 1-12 in Table 1, Relay Loadability Evaluation Criteria (“Table 1”), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Relay pickup setting criteria values related to synchronous generators are derived from the unit’s maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and the unit’s Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit’s nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard.

Relay pickup setting criteria values related to asynchronous generators (including inverter-based installations) are derived from the site’s aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), including the Mvar output of any static or dynamic reactive power devices.

For the application case where synchronous and asynchronous generator types are combined on a generator step-up transformer or on a generator interconnection Facility, the pickup setting criteria shall be determined by vector summing the pickup setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer’s impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Any relay elements that are in service only during start up, when the generator is disconnected, or when other Protection System components fail are excluded. Examples of exclusions include, but are not limited to, the following:

- Load-responsive protective 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),
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (in order to prevent false operation in the event of a blown secondary fuse) provided the distance element is set in accordance with the criteria outlined in the standard,

Table 1

The Table is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., generator step-up transformers and generator interconnection Facilities). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive protective relay (e.g., 21, 51, or 67) according to the applied application in the first column. A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word “OR,” and reveals to the reader that the relay for that application has one or more options (i.e., “ways”) to determine the bus voltage and pickup setting criteria in the fourth and fifth column, respectively. The bus voltage column and pickup setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by alternately shading groups of relays within a similar application. Also, intentional buffers were added to the table such that similar options would be paired together on a per page basis. Note that some applications may have additional pairing that might occur on adjacent pages.

<table>
<tr><th colspan="5">Table 1: Relay Loadability Evaluation Criteria</th></tr>
<tr><th>Application</th><th>Relay Type</th><th>Option</th><th>Bus Voltage[5]</th><th>Pickup Setting Criteria</th></tr>
<tr><td rowspan="6">Generator step-up transformer connected to synchronous generators</td><td rowspan="5">Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of GSU
If the relay is installed on the high-side of GSU use Option 7</td><td>1a</td><td>Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer</td><td>The impedance element shall be set less than the calculated impedance derived from 115% of:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and
(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor</td></tr>
<tr><td colspan="3">OR</td></tr>
<tr><td>1b</td><td>Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)</td><td>The impedance element shall be set less than the calculated impedance derived from 115% of:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and
(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor</td></tr>
<tr><td colspan="3">OR</td></tr>
<tr><td>1c</td><td>Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing</td><td>The impedance element shall be set less than the calculated impedance derived from 115% of:
(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and
(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation</td></tr>
<tr><td colspan="4">The same application continues on the next page with a different relay type</td></tr>
</table>

[5] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1: **Relay Loadability Evaluation Criteria**				
Application	**Relay Type**	**Option**	**Bus Voltage**[5]	**Pickup Setting Criteria**
Generator step-up transformer connected to synchronous generators	Phase time overcurrent relay (51) – installed on generator-side of GSU If the relay is installed on the high-side of GSU use Option 8	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1: **Relay Loadability Evaluation Criteria**

Application	Relay Type	Option	Bus Voltage[5]	Pickup Setting Criteria
Generator step-up transformer connected to synchronous generators	Phase directional time overcurrent relay (67) – directional toward the Transmission system– installed on generator-side of GSU If the relay is installed on the high-side of GSU use Option 9	3a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		3b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		3c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

A different application starts on the next page

Table 1: **Relay Loadability Evaluation Criteria**				
Application	**Relay Type**	**Option**	**Bus Voltage**[5]	**Pickup Setting Criteria**
Generator step-up transformer connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of GSU If the relay is installed on the high-side of GSU use Option 10	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51) – installed on generator-side of GSU If the relay is installed on the high-side of GSU use Option 11	5	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

Table 1: **Relay Loadability Evaluation Criteria**				
Application	**Relay Type**	**Option**	**Bus Voltage**[5]	**Pickup Setting Criteria**
	Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of GSU If the relay is installed on the high-side of GSU use Option 12	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application begins below				
Generator interconnection Facilities connected to synchronous generators	Phase distance relay (21) – directional toward the Transmission system	7a	0.85 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		7b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1: **Relay Loadability Evaluation Criteria**				
Application	**Relay Type**	**Option**	**Bus Voltage**[5]	**Pickup Setting Criteria**
Generator interconnection Facilities connected to synchronous generators	Phase time overcurrent relay (51)	8a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		8b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1: **Relay Loadability Evaluation Criteria**				
Application	**Relay Type**	**Option**	**Bus Voltage**[5]	**Pickup Setting Criteria**
Generator interconnection Facilities connected to synchronous generators	Phase directional time overcurrent relay (67) – directional toward the Transmission system	9a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		9b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation

A different application starts on the next page

Table 1: **Relay Loadability Evaluation Criteria**				
Application	**Relay Type**	**Option**	**Bus Voltage**[5]	**Pickup Setting Criteria**
Generator interconnection Facilities connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system	10	1.0 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51)	11	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase directional time overcurrent relay (67) – directional toward the Transmission system	12	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

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. The Standards Committee approved the Supplemental SAR regarding PRC-023-2 for posting on January 16-17, 2013.
2. The Supplemental SAR was posted for formal comment on January 25, 2013.

Description of Current Draft

The Generator Relay Loadability Standard Drafting Team (GENRLOSDT) is posting Draft 1 of PRC-023-3 – Transmission Relay Loadability for a 30-day formal comment period.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	April 2013
45-day Formal Comment Period and Initial Ballot	August 2013
10-day Recirculation Ballot	October 2013
BOT adoption	November 2013
File with FERC	December 2013

Effective Dates

See PRC-023-3 Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision

Version	Date	Action	Change Tracking
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	TBD	Clarify applicability for consistency with PRC-025-1 and other minor corrections	Supplemental SAR (Project 2010-13.2)

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.

No new or revised term is being proposed.

A. Introduction

1. **Title: Transmission Relay Loadability**

2. **Number:** PRC-023-3

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. Functional Entity

4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1, 4.2.3, or 4.2.4 *(Circuits Subject to Requirements R1 – R5, R7, and R8)*.

4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-~~2~~3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1, 4.2.3, or 4.2.4 *(Circuits Subject to Requirements R1 – R5, R7, and R8)*, provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinator

4.2. Circuits

4.2.1 Circuits Subject to Requirements R1 – R5

4.2.1.1 Transmission lines operated at 200 kV and above.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

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

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.

4.2.2 Circuits Subject to Requirement R6

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES

4.2.3 Circuits Subject to Requirement R7

4.2.3.1 Transmission lines that are used solely to export energy directly from a BES generating unit or generating plant to the network.

4.2.4 Circuits Subject to Requirement R8

4.2.4.1 Transformers with low voltage terminals connected below 200 kV, including generator step-up transformers, that are used solely to export energy directly from a BES generating unit or generating plant to the network.

5. **Effective Dates:** See Implementation Plan

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~~Effective Dates~~

~~First day of the first calendar quarter 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 calendar quarter 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

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. 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] [Time Horizon: Long Term Planning]*.

Criteria:

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).

2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).

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:

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

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.

[1] 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.

- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.

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).

~~**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.~~

6. Not used.

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.

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.

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.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays 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

10.1 Set load responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 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, for at least 15 minutes to provide time 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 set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

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:

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

b. 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.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

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. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion ~~6,~~ 7, 8, 9, 12, or 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]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-3 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-3, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

R7. Each Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator interconnection Facility. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning].*

R8. Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator step-up transformer. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning].*

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion ~~6,~~ 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe.

M7. Each Transmission Owner and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) to show that each of its generator interconnection Facility relays is set according to one of the criteria in Attachment C. (R7)

M8. Each Transmission Owner and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) to show that each of its generator step-up transformer relays is set according to one of the criteria in Attachment C. (R8)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

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

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5, R7, and R8 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per R6.

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

The Compliance Enforcement Authority shall keep the last audit record 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.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 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. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion ~~6,~~ 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the

Requirement	Lower	Moderate	High	Severe
				Facility Rating of the circuit. OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities

Requirement	Lower	Moderate	High	Severe
		must comply with the standard and met parts 6.1 and 6.2, but more than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after	must comply with the standard and met parts 6.1 and 6.2, but 24 months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	must comply with the standard. OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its

Requirement	Lower	Moderate	High	Severe
		the list was established or updated. (part 6.2)		Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.
R7	N/A	N/A	N/A	The responsible entity did not set one of its generator interconnection Facility relays in accordance with the criteria in Attachment C.
R8	N/A	N/A	N/A	The responsible entity did not set one of its generator step-up transformer relays in accordance with the criteria in Attachment C.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. 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, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

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~~Version History~~

~~Version~~	~~Date~~	~~Action~~	~~Change Tracking~~
~~1~~	~~February 12, 2008~~	~~Approved by Board of Trustees~~	~~New~~
~~1~~	~~March 19, 2008~~	~~Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."~~	~~Errata~~
~~1~~	~~March 18, 2010~~	~~Approved by FERC~~	
~~1~~	~~Filed for approval April 19, 2010~~	~~Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733~~	~~Revision~~
~~2~~	~~March 10, 2011 approved by Board of Trustees~~	~~Revised to address initial set of directives from Order 733~~	~~Revision (Project 2010-13)~~
~~2~~	~~March 15, 2012~~	~~FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)~~	
~~3~~	~~TBD~~	~~Clarify applicability for consistency with PRC-025-1 and other minor corrections~~	~~Supplemental SAR (Project 2010-13.2)~~

PRC-023-3 — 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).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

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

2.1. 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 except as noted in section 1.6

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

~~**2.4.** Generator protection relays that are susceptible to load.~~

2.4. Protective relays applied at the terminals of generation Facilities in accordance with NERC Reliability Standard PRC-025-1 or its successor(s).

2.5. Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-3 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is a monitored Facility of an IROL, where the IROL was determined in the planning horizon pursuant to FAC-010.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

PRC-023-3 — Attachment C

The following criteria shall be used to set load-responsive relays on generator interconnection Facilities and generator-step-up transformers.

This standard does not require the responsible entity to use any of the protective functions listed in Table 1. Each responsible entity that applies load-responsive protective relays on Facilities listed in 4.2.3 and 4.2.4, Facilities shall use one of the following Options 1-12 in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.

Relay pickup setting criteria values related to synchronous generators are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard.

Relay pickup setting criteria values related to asynchronous generators (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), including the Mvar output of any static or dynamic reactive power devices.

For the application case where synchronous and asynchronous generator types are combined on a generator step-up transformer or on a generator interconnection Facility, the pickup setting criteria shall be determined by vector summing the pickup setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.

Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Any relay elements that are in service only during start up, when the generator is disconnected, or when other Protection System components fail are excluded. Examples of exclusions include, but are not limited to, the following:

- Load-responsive protective 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),
- Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (in order to prevent false operation in the event of a blown secondary fuse) provided the distance element is set in accordance with the criteria outlined in the standard,

Table 1

The Table is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.

The first column identifies the application (e.g., generator step-up transformers and generator interconnection Facilities). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.

The second column identifies the load-responsive protective relay (e.g., 21, 51, or 67) according to the applied application in the first column. A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text.

The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word "OR," and reveals to the reader that the relay for that application has one or more options (i.e., "ways") to determine the bus voltage and pickup setting criteria in the fourth and fifth column, respectively. The bus voltage column and pickup setting criteria columns provide the criteria for determining an appropriate setting.

The table is further formatted by alternately shading groups of relays within a similar application. Also, intentional buffers were added to the table such that similar options would be paired together on a per page basis. Note that some applications may have additional pairing that might occur on adjacent pages.

Table 1: Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Pickup Setting Criteria**
Generator step-up transformer connected to synchronous generators	Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of GSU If the relay is installed on the high-side of GSU use Option 7	1a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		1b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		1c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

[5] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.

Table 1: Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage**[5]	**Pickup Setting Criteria**
Generator step-up transformer connected to synchronous generators	Phase time overcurrent relay (51) – installed on generator-side of GSU If the relay is installed on the high-side of GSU use Option 8	2a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		2b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		2c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1: Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Pickup Setting Criteria**
Generator step-up transformer connected to synchronous generators	Phase directional time overcurrent relay (67) – directional toward the Transmission system– installed on generator-side of GSU If the relay is installed on the high-side of GSU use Option 9	3a	Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		3b	Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		3c	Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

Table 1: Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Pickup Setting Criteria**
Generator step-up transformer connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of GSU If the relay is installed on the high-side of GSU use Option 10	4	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51) – installed on generator-side of GSU If the relay is installed on the high-side of GSU use Option 11	5	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	The same application continues on the next page with a different relay type			

Table 1: Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Pickup Setting Criteria**
	Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of GSU If the relay is installed on the high-side of GSU use Option 12	6	Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
A different application begins below				
Generator interconnection Facilities connected to synchronous generators	Phase distance relay (21) – directional toward the Transmission system	7a	0.85 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		7b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The impedance element shall be set less than the calculated impedance derived from 115% of: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1: Relay Loadability Evaluation Criteria

Application	Relay Type	Option	Bus Voltage[5]	Pickup Setting Criteria
Generator interconnection Facilities connected to synchronous generators	Phase time overcurrent relay (51)	8a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		8b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
	The same application continues on the next page with a different relay type			

Table 1: Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage**[5]	**Pickup Setting Criteria**
Generator interconnection Facilities connected to synchronous generators	Phase directional time overcurrent relay (67) – directional toward the Transmission system	9a	0.85 per unit of the line nominal voltage	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output – 120% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor
		OR		
		9b	Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing	The overcurrent element shall be set greater than 115% of the calculated current derived from: (1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and (2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation
A different application starts on the next page				

Table 1: Relay Loadability Evaluation Criteria				
Application	**Relay Type**	**Option**	**Bus Voltage[5]**	**Pickup Setting Criteria**
Generator interconnection Facilities connected to asynchronous generators only (including inverter-based installations)	Phase distance relay (21) – directional toward the Transmission system	10	1.0 per unit of the line nominal voltage	The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase time overcurrent relay (51)	11	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
	Phase directional time overcurrent relay (67) – directional toward the Transmission system	12	1.0 per unit of the line nominal voltage	The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)
End of Table 1				

Implementation Plan

PRC-023-3 – Transmission Relay Loadability

Project 2010-13.2 Phase II Relay Loadability

Requested Approvals

- PRC-023-3 – Transmission Relay Loadability

Requested Retirements

- PRC-023-2 – Transmission Relay Loadability

Prerequisite Approvals

- PRC-025-1 – Generator Relay Loadability*
  *A supplemental SAR was approved by the Standards Committee at their January 16-17, 2013 meeting to authorize the drafting team to make changes to PRC-023-2 to comport with the proposed draft PRC-025-1 – Generator Relay Loadability in order to establish a bright line between the applicability of load-responsive protective relays in the current transmission and the proposed generator relay loadability standards.

Revisions to Defined Terms in the NERC Glossary

- None

Background

The generator relay loadability standard drafting team and industry stakeholders raised a concern that there is no bright line to clearly distinguish which load-responsive protective relays pertain to the existing PRC-023-2 – Transmission Relay Loadability standard, effective in the United States on July 1, 2012, and the proposed PRC-025-1 – Generator Relay Loadability standard. To resolve this concern, the drafting team proposed to modify the applicability section of PRC-023-2. The standard drafting team clarified, for each functional entity, the applicability of PRC-023-2 by tying applicability to the terminal the load-responsive protective relay is connected to within the Transmission system.

Requirements R1 though R6 continue to apply to the Generator Owner to avoid a potential gap in situations where this entity owns load-responsive protective relays subject to transmission line relay loadability (PRC-023). These situations could be the result of a current configuration or future changes or additions in transmission configurations.

The proposed PRC-023-3 standard also includes two new Requirements, R7 and R8 to address load-responsive protective relay loadability in cases where the Distribution Provider or Transmission Owner owns generator interconnection Facilities or generator step-up (GSU) transformers. The implementation time for Requirements R7 and R8 comports with the periods established in the proposed PRC-025-1 Implementation Plan.

General Considerations

It is expected that the implementation period for PRC-023-2 will have been achieved, in part, by the time PRC-023-3 is adopted by the NERC Board of Trustees and by the time of other approvals by applicable governmental authorities. The proposed PRC-023-3 Implementation Plan now reflects specific milestone dates that are known, time periods consistent with PRC-023-2, and an implementation period for new Requirements R7 and R8.

Applicable Entities

- Distribution Provider
- Generator Owner
- Planning Coordinator
- Transmission Owner

Effective Date

New Standard

PRC-023-3	First day of the first calendar quarter 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 calendar quarter 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.

Standards for Retirement

PRC-023-2	Midnight of the day immediately prior to the Effective Date of PRC-023-3 – Transmission Relay Loadability in the particular jurisdiction in which the new standard is becoming effective.

Implementation Plan for Definitions

No definitions are proposed as a part of this standard.

Implementation Plan for PRC-023-3, Requirements R1 through R6

Each Distribution Provider, Generator Owner, Planning Coordinator, and Transmission Owner applicable to this standard shall be 100% compliant on the following dates:

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1	Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above, except as noted below.	First day of the first calendar quarter, after applicable regulatory approvals	First calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
	• For supervisory elements as described in PRC-023-3 - Attachment A, Section 1.6	The later of July 1, 2014 or first day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
	• For switch-on-to-fault schemes as described in PRC-023-3 - Attachment A, Section 1.3	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1 (continued)	Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date
R2 and R3	Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R2 and R3 continued	Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date
R4	Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability	First day of the first calendar quarter six months after applicable regulatory approvals	First day of the first calendar quarter six months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R5	Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
R6	Each Planning Coordinator shall conduct an assessment by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owner, and Distribution Providers must comply with Requirements R1 through R5	Later of January 1, 2014 or the first day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Implementation Plan for PRC-023-3, Requirements R7 and R8

Load-responsive protective relays subject to the standard

Each Transmission Owner and Distribution Provider that owns load-responsive protective relays applicable to this standard shall be 100% compliant on the following dates:

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R7	Each Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator interconnection Facility.	Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months after applicable regulatory approvals	Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
		Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months after applicable regulatory approvals	Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R8	Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator step-up transformer.	Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months after applicable regulatory approvals	Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
		Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months after applicable regulatory approvals	Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Load-responsive protective relays which become applicable to the standard

Each Transmission Owner and Distribution Provider that owns load-responsive protective relays that become applicable to this standard, not because of the actions of the Transmission Owner and Distribution Provider including, but not limited to changes in NERC Registration Criteria, Bulk Electric System (BES) definition, or any other non-Generator Owner action, shall be 100% compliant on the following dates:

<table>
<tr><th rowspan="2">Requirement</th><th rowspan="2">Applicability</th><th colspan="2">Implementation Date</th></tr>
<tr><th>Jurisdictions where Regulatory Approval is Required</th><th>Jurisdictions where No Regulatory Approval is Required</th></tr>
<tr><td rowspan="2">R7</td><td rowspan="2">Each Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator interconnection Facility.</td><td>Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months beyond the date the load-responsive protective relays become applicable to the standard</td><td>Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months beyond the date the load-responsive protective relays become applicable to the standard</td></tr>
<tr><td>Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months beyond the date the load-responsive protective relays become applicable to the standard</td><td>Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months beyond the date the load-responsive protective relays become applicable to the standard</td></tr>
</table>

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R8	Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator step-up transformer.	Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months beyond the date the load-responsive protective relays become applicable to the standard	Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months beyond the date the load-responsive protective relays become applicable to the standard
		Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months beyond the date the load-responsive protective relays become applicable to the standard	Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months beyond the date the load-responsive protective relays become applicable to the standard

Revisions or Retirements to Already Approved Standards

The following table identifies the sections of the approved standard that shall be added, retired, or revised when this standard is implemented. If the drafting team is recommending revisions, those changes are identified in **bold blue with underlining for additions** and for ~~**deletions in bold red with a strikeout**~~.

Already Approved Standard	Proposed Replacement
PRC-023-2 4.1. Functional Entity 4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* 4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* 4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1*(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities. 4.1.4 Planning Coordinators	**PRC-023-3** 4.1.Functional Entity 4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023-2 3 - Attachment A, applied **at the terminals of the** ~~**to**~~ circuits defined in 4.2.1**, 4.2.3, or 4.2.4** *(Circuits Subject to Requirements R1 – R5**, R7, and R8**).* 4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied **at the terminals of the** ~~**to**~~ circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* 4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023-2 3 - Attachment A, applied **at the terminals of the** ~~**to**~~ circuits defined in 4.2.1**, 4.2.3, or 4.2.4** *(Circuits Subject to Requirements R1 – R5**, R7, and R8**)*, provided those circuits have bi-directional flow capabilities. 4.1.4 Planning Coordinators
Notes: The change in the proposed PRC-023-3 Applicability creates a bright line between those load-responsive protective relays that are applicable to PRC-023-3 – Transmission Relay Loadability and the proposed PRC-025-1 – Generator Relay Loadability. This is evident by the minor changes to the Applicability text to distinguish the applicability of the relays by which "terminal" the load-responsive protective relay is connected to within the Transmission system.	

Already Approved Standard	Proposed Replacement
PRC-023-2 **None.**	**PRC-023-3** **New applicability** 4.2 Circuits 4.2.3 Circuits Subject to Requirement R7 4.2.3.1 Transmission lines that are used solely to export energy directly from a BES generating unit or generating plant to the network. 4.2.4 Circuits Subject to Requirement R8 4.2.2.2 Transformers with low voltage terminals connected below 200 kV, including generator step-up transformers, that are used solely to export energy directly from a BES generating unit or generating plant to the network.
Notes: The above two new applicability items for circuits subject to the standard were added to address to situations where the Distribution Provider or Transmission Owner own either generator interconnection Facilities or generator step-up (GSU) transformers, respectively.	
PRC-023-2 R1, Criterion 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.	**PRC-023-3** **New Requirement** R7. Each Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator interconnection Facility. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning].*
Notes: This new requirement is included to address a gap concerning generator step-up (GSU) transformers where the Transmission Owner or Distribution Provider has applied load-responsive protective relays. Referencing the proposed Applicability section 4.2.4, Circuits Subject to Requirement R8, this requirement closes the gap for those transformers that have low voltage terminals connected below 200 kV. Currently, only those Transmission system transformers with low voltage terminals connected at 200 kV and above are applicable to the Transmission Owner or	

<table>
<tr><th>Already Approved Standard</th><th>Proposed Replacement</th></tr>
<tr><td colspan="2">Distribution Provider or transformers with low voltage terminals under 200 kV if the Planning Coordinator determines (in accordance with requirement R6) that they should be subject to PRC-023-3. This is identified by in the proposed Applicability 4.2.1.4. This requirement eliminates the gap between the proposed PRC-023-3 and PRC-025-1 so that generator step-up (GSU) transformers (i.e., where the Transmission system transformer is the transmission line termination – Criterion 10) apply to the Transmission Owner or Distribution Provider in the proposed PRC-023-3 in the same manner as the Generator Owner in the proposed PRC-025-1.
Circuits subject to R8 are primarily GSU transformers and also include “aggregated generator transformers” – those connecting wind farms, and photovoltaic sites.</td></tr>
<tr><td>PRC-023-2
None.</td><td>PRC-023-3
New Requirement
R8. Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator step-up transformer. [Violation Risk Factor: High] [Time Horizon: Long Term Planning].</td></tr>
<tr><td colspan="2">Notes: The above new Requirement R7 addresses a gap between the proposed PRC-023-3 and PRC-025-1 standards. This requirement applies to the condition where the Transmission Owner or Distribution Provider apply load-responsive protective relays on a generator interconnection Facility(ies). Rather than add Transmission Owner and Distribution Provider to the proposed PRC-025-1, it was equally and efficient to include the same loadability criteria as the proposed PRC-025-1 in the proposed PRC-023-3 standard. Requirement R7 proposes to replace the current PRC-023-2, Requirement R1, Criterion 6 with a new requirement. Criterion 6 for setting the load-responsive protective relays so they do not operate at or below 230% now has additional flexibility in setting such relays according to Attachment C which is referenced in this new Requirement, R7. The 230% criterion comports with the loadability criteria found in the proposed PRC-023-3 Attachment C. The Transmission Owner and Distribution Provider in the proposed PRC-023-3 will have the same options for setting its load-responsive protective relays when applied on generator interconnection Facility(ies) as the Generator Owner in the proposed PRC-025-1.</td></tr>
</table>

Implementation Plan

Project 2010-13.2 - Relay Loadability: Generator

PRC-023-3 – Transmission Relay Loadability

Project 2010-13.2 Phase II Relay Loadability

Requested Approvals

- PRC-023-3 – Transmission Relay Loadability

Requested Retirements

- PRC-023-2 – Transmission Relay Loadability

Prerequisite Approvals

- PRC-025-1 – Generator Relay Loadability*

  *A supplemental SAR was approved by the Standards Committee at their January 16-17, 2013 meeting to authorize the drafting team to make changes to PRC-023-2 to comport with the proposed draft PRC-025-1 – Generator Relay Loadability ~~and~~ in order to establish a bright line between the applicability of load-responsive protective relays in the current transmission and the proposed generator relay loadability standards.

Revisions to Defined Terms in the NERC Glossary

- None

Background

The generator relay loadability standard drafting team and industry stakeholders raised a concern that there is no bright line to clearly distinguish which load-responsive protective relays pertain to the~~about the potential for overlap between~~ existing PRC-023-2 – Transmission Relay Loadability standard, effective in the United States on July 1, 2012, and the proposed PRC-025-1 – Generator Relay Loadability ~~standards. The concern is that there was no bright line to clearly distinguish which load-responsive protective relays pertain to each~~ standard. To resolve this concern, the ~~The~~ drafting team ~~researched the issue and~~ proposed to modify the applicability section of PRC-023-2. The standard drafting team clarified, for ~~to clarify the~~ each functional entity, the~~entity's~~ applicability of PRC-023-2 by tying applicability to the~~with respect to which~~ terminal the load-responsive protective relay is connected to within the Transmission system.

Requirements R1 though R6 continue to apply to the Generator Owner to avoid a potential gap in situations where this entity owns load-responsive protective relays subject to transmission line relay loadability (PRC-

023). These situations could be the result of a current configuration or future changes or additions in transmission configurations.

The proposed PRC-023-3 standard also includes two new Requirements, R7 and R8 to address load-responsive protective relay loadability in cases where the Distribution Provider or Transmission Owner owns generator interconnection Facilities or generator step-up (GSU) transformers. The implementation time for Requirements R7 and R8 comports with the periods established in the proposed PRC-025-1 Implementation Plan.

General Considerations

It~~The Implementation Plan period reflects consideration that a specific period is not required because no new entity or facilities are subject to compliance. Also, it~~ is expected that the implementation ~~plan and~~ period for PRC-023-2 will have been achieved, ~~and that it will not need to be considered~~ in part, by the time PRC-023-3 is adopted by the NERC Board of Trustees and by the time of other approvals by applicable governmental authorities. The proposed PRC-023-3 Implementation Plan now reflects specific milestone dates that are known, time periods consistent~~conjunction~~ with PRC-023-2, and an implementation period for new Requirements R7 and R8. ~~this revision.~~

Applicable Entities

- Distribution Provider
- Generator Owner
- Planning Coordinator
- Transmission Owner

Effective Date

New Standard

PRC-023-3	First day of the first calendar quarter 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 calendar quarter 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.

Standards for Retirement

PRC-023-2	Midnight of the day immediately prior to the Effective Date of PRC-023-3~~2~~ –

Transmission Relay Loadability in the particular jurisdiction in which the new standard is becoming effective.

Implementation Plan for Definitions

No definitions are proposed as a part of this standard.

Implementation Plan for PRC-023-3, Requirements R1 through R6~~All requirements~~

Each Distribution Provider, Generator Owner, Planning Coordinator, and Transmission Owner applicable to this standard shall be 100% compliant on the following dates:~~effective date of the standard according to the jurisdiction.~~

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1	Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above, except as noted below.	First day of the first calendar quarter, after applicable regulatory approvals	First calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
	• For supervisory elements as described in PRC-023-3 - Attachment A, Section 1.6	The later of July 1, 2014 or first day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
	• For switch-on-to-fault schemes as described in PRC-023-3 - Attachment A, Section 1.3	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
R1 (continued)	Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R2 and R3	Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
R2 and R3 continued	Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R4	Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability	First day of the first calendar quarter six months after applicable regulatory approvals	First day of the first calendar quarter six months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
R5	Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
R6	Each Planning Coordinator shall conduct an assessment by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owner, and Distribution Providers must comply with Requirements R1 through R5	Later of January 1, 2014 or the first day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Implementation Plan for PRC-023-3, Requirements R7 and R8

Load-responsive protective relays subject to the standard

Each Transmission Owner and Distribution Provider that owns load-responsive protective relays applicable to this standard shall be 100% compliant on the following dates:

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R7	Each Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator interconnection Facility.	Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months after applicable regulatory approvals	Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
		Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months after applicable regulatory approvals	Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R8	Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator step-up transformer.	Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months after applicable regulatory approvals	Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
		Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months after applicable regulatory approvals	Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Load-responsive protective relays which become applicable to the standard

Each Transmission Owner and Distribution Provider that owns load-responsive protective relays that become applicable to this standard, not because of the actions of the Transmission Owner and Distribution Provider including, but not limited to changes in NERC Registration Criteria, Bulk Electric System (BES) definition, or any other non-Generator Owner action, shall be 100% compliant on the following dates:

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R7	Each Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator interconnection Facility.	Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months beyond the date the load-responsive protective relays become applicable to the standard	Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months beyond the date the load-responsive protective relays become applicable to the standard
		Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months beyond the date the load-responsive protective relays become applicable to the standard	Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months beyond the date the load-responsive protective relays become applicable to the standard

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R8	Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator step-up transformer.	Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months beyond the date the load-responsive protective relays become applicable to the standard	Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months beyond the date the load-responsive protective relays become applicable to the standard
		Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months beyond the date the load-responsive protective relays become applicable to the standard	Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months beyond the date the load-responsive protective relays become applicable to the standard

Revisions or Retirements to Already Approved Standards

The following table identifies the sections of the approved standard that shall be added, retired~~,~~ or revised when this standard is implemented. If the drafting team is recommending revisions, those changes are identified in **bold**~~the retirement or revision of a requirement, that text is~~ blue **with underlining for additions** and for ~~**deletions in bold red with a strikeout**~~.

Already Approved Standard	Proposed Replacement ~~Requirement(s)~~
PRC-023-2 4.1. Functional Entity 4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* 4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* 4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1*(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities. 4.1.4 Planning Coordinators	**PRC-023-3** 4.1.Functional Entity 4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023-2 3 - Attachment A, applied **at the terminals of the** ~~**to**~~ circuits defined in 4.2.1**, 4.2.3, or 4.2.4** *(Circuits Subject to Requirements R1 – R5**, R7, and R8**).* 4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023-3~~2~~ - Attachment A, applied **at the terminals of the** ~~**to**~~ circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* 4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023-2 3 - Attachment A, applied **at the terminals of the** ~~**to**~~ circuits defined in 4.2.1**, 4.2.3, or 4.2.4** *(Circuits Subject to Requirements R1 – R5**, R7, and R8**)*, provided those circuits have bi-directional flow capabilities. 4.1.4 Planning Coordinators
Notes: The change in the proposed PRC-023-3 Applicability~~applicability~~ creates a bright line between those load-responsive protective relays that are applicable to PRC-023-3 – Transmission Relay Loadability and the proposed PRC-025-1 – Generator Relay Loadability. This is evident by the minor changes to the A~~a~~pplicability text to distinguish the applicability of the relays by which "terminal" the load-responsive protective relay is connected to within the Transmission system.	

Already Approved Standard	Proposed Replacement ~~Requirement(s)~~
PRC-023-2 **None.**	**PRC-023-3** **New applicability** 4.2 Circuits 4.2.3 Circuits Subject to Requirement R7 4.2.3.1 Transmission lines that are used solely to export energy directly from a BES generating unit or generating plant to the network. 4.2.4 Circuits Subject to Requirement R8 4.2.2.2 Transformers with low voltage terminals connected below 200 kV, including generator step-up transformers, that are used solely to export energy directly from a BES generating unit or generating plant to the network.
Notes: The above two new applicability items for circuits subject to the standard were added to address to situations where the Distribution Provider or Transmission Owner own either generator interconnection Facilities or generator step-up (GSU) transformers, respectively.	
PRC-023-2 R1, Criterion 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.	**PRC-023-3** **New Requirement** R7. Each Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator interconnection Facility. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning].*
Notes: This new requirement is included to address a gap concerning generator step-up (GSU) transformers where the Transmission Owner or Distribution Provider has applied load-responsive protective relays. Referencing the proposed Applicability section 4.2.4, Circuits Subject to Requirement R8, this requirement closes the gap for those transformers that have low voltage terminals connected below 200 kV. Currently, only those Transmission system transformers with low voltage terminals connected at 200 kV and above are applicable to the Transmission Owner or	

Already Approved Standard	Proposed Replacement ~~Requirement(s)~~
Distribution Provider or transformers with low voltage terminals under 200 kV if the Planning Coordinator determines (in accordance with requirement R6) that they should be subject to PRC-023-3. This is identified by in the proposed Applicability 4.2.1.4. This requirement eliminates the gap between the proposed PRC-023-3 and PRC-025-1 so that generator step-up (GSU) transformers (i.e., where the Transmission system transformer is the transmission line termination – Criterion 10) apply to the Transmission Owner or Distribution Provider in the proposed PRC-023-3 in the same manner as the Generator Owner in the proposed PRC-025-1. Circuits subject to R8 are primarily GSU transformers and also include "aggregated generator transformers" – those connecting wind farms, and photovoltaic sites.	
PRC-023-2 None.	**PRC-023-3** **New Requirement** R8. Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator step-up transformer. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning].*
Notes: The above new Requirement R7 addresses a gap between the proposed PRC-023-3 and PRC-025-1 standards. This requirement applies to the condition where the Transmission Owner or Distribution Provider apply load-responsive protective relays on a generator interconnection Facility(ies). Rather than add Transmission Owner and Distribution Provider to the proposed PRC-025-1, it was equally and efficient to include the same loadability criteria as the proposed PRC-025-1 in the proposed PRC-023-3 standard. Requirement R7 proposes to replace the current PRC-023-2, Requirement R1, Criterion 6 with a new requirement. Criterion 6 for setting the load-responsive protective relays so they do not operate at or below 230% now has additional flexibility in setting such relays according to Attachment C which is referenced in this new Requirement, R7. The 230% criterion comports with the loadability criteria found in the proposed PRC-023-3 Attachment C. The Transmission Owner and Distribution Provider in the proposed PRC-023-3 will have the same options for setting its load-responsive protective relays when applied on generator interconnection Facility(ies) as the Generator Owner in the proposed PRC-025-1.	

Unofficial Comment Form

Project 2010-13.2 Phase II Relay Loadability

(PRC-025-1 and PRC-023-2)

Please **DO NOT** use this form for submitting comments. Please use the electronic form [insert hyperlink to electronic form] located at the link below to submit comments on the Standard. The electronic comment form must be completed by May 24, 2013. If you have questions please contact Scott Barfield-McGinnis at Scott.Barfield@nerc.net or by telephone at (404) 446-9689.

http://www.nerc.com/filez/standards/Project_2010-13.2_Summary_Table.html

Background Information

This posting is soliciting formal comments in a 30-day formal comment period.

The Standard Authorization Request (SAR) for this project was initiated on August 5, 2010 and approved by the Standards Committee (SC) on August 12, 2010. It established the scope of work for Project 2010-13.2 for what is the second phase of Order 733, Transmission Relay Loadability Reliability Standard.[1] Phase I resulted in the NERC Reliability Standard PRC-023-1 and Phase II concerning this project specifically addresses protecting the generator, generator step-up (GSU) transformer, and unit auxiliary transformers (UAT) in the proposed new standard, PRC-025-1. The SC moved this project into active development on March 8, 2012.

During analysis of many of the major disturbances in the last 25 years on the North American interconnected power system, generators have been found to have tripped for conditions that did not apparently pose a direct risk to those generators and associated equipment within the time period where the tripping occurred. This unnecessary tripping has often been evaluated to have extended the scope and/or duration of that disturbance. This was noted, in detail, to be a serious issue in the August 2003 “blackout’ in the northeastern North American continent.

During the recoverable phase of a disturbance, the disturbance may exhibit a “voltage disturbance” behavior pattern, where system voltage is widely depressed. In order to support the system during this phase of a disturbance, this standard establishes criteria for setting load-responsive relays such that individual generators may provide Reactive Power within their dynamic capability during transient time periods to help the system recover from that voltage disturbance. The premature or unnecessary tripping of generators resulting in the removal of dynamic Reactive Power exacerbates the severity of the voltage disturbance, and as a result

[1] Transmission Relay Loadability Reliability Standard, Order No. 733, 130 FERC ¶ 61,221 (2010), Paragraphs 104, 105, 106, and 108.

changes the character of the system disturbance. In addition, the loss of Real Power could initiate or exacerbate a frequency disturbance.

The Standard Drafting Team has developed draft three of the standard to provide requirements that address these concerns, and is presenting this draft to industry for a formal comment period to get industry comments to aid in further development.

Summary of changes

The generator relay loadability standard drafting team ("SDT") has revised the proposed the draft of PRC-023-3 – Transmission Relay Loadability based on stakeholder comments received during the Standard Authorization Request (SAR) 45-day formal posting of the SAR which included a redline to the PRC-023-2 standard. The SAR was not modified by the standard drafting team. Contemporaneously with the SAR posting, the SDT has revised the proposed draft of PRC-025-1 – Generator Relay Loadability during its 45-day formal comment posting of the standard and initial ballot which received 54.65% stakeholder approval. The following narrative is a summary of the significant improvements made to the above standards.

Standard (PRC-023-3)

- Applicability
    - The phase "at the terminal of the" was inserted in for each applicable entity of the standard to create a bright light between the proposed PRC-023-3 and PRC-025-1 standards
    - References to the two new Requirements (R7 and R8) was inserted for the applicable Distribution Provider and Transmission Owner
    - References to the two new Applicability for Circuits (4.2.3 and 4.24) were inserted for the applicable Distribution Provider and Transmission Owner
    - Applicability 4.2.3 – Circuits Subject to Requirement R7 was added to create a bright line between the proposed PRC-023-3 and PRC-025-1 standards for the Distribution Provider and Transmission Owner regarding generator interconnection Facilities
    - Applicability 4.2.4 – Circuits Subject to Requirement R8 was added to create a bright line between the proposed PRC-023-3 and PRC-025-1 standards for the Distribution Provider and Transmission Owner regarding generator step-up (GSU) transformers
- Requirements
    - Requirement R1, Criterion 6 was removed and replaced by two new proposed Requirements R7 and R8
    - New Requirement R7 applicable to the Distribution Provider and Transmission Owner regarding generator interconnection Facilities to create a bright line between the proposed PRC-023-3 and PRC-025-1 in applying settings to load-responsive protective relay for loadability
    - New Requirement R8 applicable to the Distribution Provider and Transmission Owner regarding generator step-up (GSU) transformer to create a bright line between the

proposed PRC-023-3 and PRC-025-1 in applying settings to load-responsive protective relay for loadability

- Measures
  - New Measure M7 was inserted to correspond to the new Requirement R7
  - New Measure M8 was inserted to correspond to the new Requirement R8

- Compliance
  - The Compliance Monitoring Responsibility section text was updated to current NERC Reliability Standards language
  - Requirements R7 and R8 were added to the Data Retention section
  - The reference to “Compliance Monitor” was updated to the more correct term, “Compliance Enforcement Authority”

- Violation Severity Levels
  - New VSL was inserted for Requirement R7
  - New VSL was inserted for Requirement R8
  - Removed references to Requirement R1, Criterion 6 because it is no longer used

- Attachment A
  - Revised criterion 2.4 to address relays applied at the terminals of generation Facilities in accordance with NERC Reliability Standard PRC-025-1 for the Planning Coordinator pursuant to Requirement R6

- Attachment C
  - Inserted new attachment to address relay loadability described in Requirements R7 and R8
  - Includes Table 1, Relay Loadability Evaluation Criteria which is the same as the criteria proposed in PRC-025-1 for generator interconnection Facilities and generator step-up (GSU) transformers

Implementation Plan (PRC-023-3)

- Updated to reflect known milestone dates based on the approvals of the current version two
- Added the implementation period for the two new Requirements (R7 and R8) to align with the same implementation period proposed in PRC-025-1

VRF/VSL Justifications (PRC-023-3)

- Provided justification for VRF/VSL for the two new Requirements R7 and R8

Standard (PRC-025-1)

- Purpose
  - Revised to remove the first occurrence of "generator"
  - Other minor revisions to provide clarity in the scope of the standard
- Applicability
  - Inserted section 3.2.5 to provide applicability to Facilities that address Elements utilized in the aggregation of dispersed power producing resources.
- Requirements
  - No change
- Measures
  - No change
- Compliance
  - No change
- Violation Severity Levels
  - No change
- Attachment 1
  - General text revisions
  - Included language to note that the standard does not require the use of any of the protective functions list in Table 1, Relay Loadability Evaluation Criteria
  - Removed the Planning Coordinator and inserted the Regional Reliability Organization to comport with the anticipated retirement of MOD-024-1 and MOD-025-1 and the approval of MOD-025-2 in both the text and Table 1
  - Inserted language to address situations where the Generator Owner may combine both asynchronous and synchronous generators on a generator interconnection Facility to provide direction on the evaluation of relay loadability
  - Update the references to no-load tap changes (NLTC) and on-load tap changers (OLTC) to the generally accepted use of the IEEE terms, deenergized tap changers (DETC) and load tap changers (LTC)
  - Added an exception to the standard for Protection Systems that detect generator overloads
  - Added an exception to the standard for Protection Systems that detect transformer overloads
  - Made minor editorial edits to Table 1 text for clarity such as replacing "connected to" with "aggregate" for consistency with other uses
  - Made minor editorial edits to remove hyphens and inserting the word "connected" (e.g., Generator step-up transformer [connected] to asynchronous generators)
  - For the application of generator interconnection Facility, reduced the Reactive Power output calculation from 150% to 120% for consistency with the previous PRC-023-2, Requirement R1, Criterion 6

Implementation Plan (PRC-025-1)

- Minor editorial edits for clarity
- Updated the implementation information to mimic the table provided in the current PRC-023-2 and proposed PRC-023-3 to delineate the implementation for jurisdictions where regulatory approval is required and in jurisdictions where no regulatory approval is necessary
- Inserted language concerning who the Real and Reactive Power is reported to by the Generator Owner to allow a transition from reporting to the Regional Reliability Organization to the Transmission Planner rather than having the Planning Coordinator as identified in the previous posting of the PRC-025-1 standard

VRF/VSL Justifications (PRC-023-3)

Inserted references to the two new Requirements R7 and R8 proposed in PRC-023-3 to support reasoning for assigning of a VRF/VSL

**Please use the electronic comment form to submit your final comments to NERC.*

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

Please note that the official comment form ***does not*** retain formatting (even if it appears to transfer formatting when you copy from the unofficial Word version of the form into the official electronic comment form). If you enter extra carriage returns, bullets, automated numbering, symbols, bolding, italics, or any other formatting, that formatting will not be retained when you submit your comments.

- Separate discrete comments by idea, e.g., preface with (1), (2), etc.
- Use brackets [] to call attention to suggested inserted or deleted text.
- Insert a “check” mark in the appropriate boxes by double-clicking the gray areas.
- **Do not use** formatting such as extra carriage returns, bullets, automated numbering, bolding, or italics.
- **Please do not repeat other entity’s comments**. Select the appropriate item to support another entity’s comments. An opportunity to enter additional or exception comments will be available.

1. Do the changes to the proposed PRC-023-2 and PRC-025-1 (listed above) provide a bright line between the two standards? If not, provide specific suggestions to improve or clarify the performance between the standards.

   ☐ Yes
   ☐ No

   Comments:

2. Does the **Table 1: Relay Loadability Evaluation Criteria** in both PRC-023-3 (Attachment C) and PRC-025-1 (Attachment 1) clearly identify the criteria for setting load-responsive protective relays? If not, provide specific detail that would improve the clarity of Table 1.

   ☐ Yes
   ☐ No

   Comments:

3. Does PRC-025-1, **Guidelines and Technical Basis** provide a clear understanding of the various criteria, including the options (e.g., 1a, 1b, 1c, 2a, etc.) for setting load-responsive protective relays? If not, provide specific detail that would improve the Guidelines and Technical Basis.

☐ Yes
☐ No

Comments:

4. The drafting team developed an Implementation Plan for the added requirements of the proposed PRC-023-3 that aligns with that proposed in PRC-025-1. Do you agree with the proposed **Implementation Plan** for PRC-023-3 Requirements R7 and R8 and the proposed PRC-025-1:
    a. 48-months to apply load-responsive protective relay settings , where relay **replacement is not required,** and
    b. 72-months to apply load-responsive protective relay settings, where relay **replacement is required?**

    If not, provide an alternative implementation plan with specific rationale for such an alternative period.

☐ Yes
☐ No

Comments:

5. Do you have any other comments? If so, please provide suggested changes and rationale.

☐ Yes
☐ No

Comments:

Violation Risk Factor and Violation Severity Level Justifications

PRC-023-3 – Transmission Relay Loadability
Project 2010-13.2 Phase II Relay Loadability

Violation Risk Factor and Violation Severity Level Justifications

This document provides the drafting team's justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in: PRC-023 – Transmission Relay Loadability.

Each primary requirement is assigned a VRF and a set of one or more VSLs. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the ERO Sanction Guidelines.

The Reliability Coordination Standard Drafting Team (SDT) applied the following NERC criteria and FERC Guidelines when proposing VRFs and VSL for the requirements under this project.

NERC Criteria – Violation Risk Factors

High Risk Requirement

A requirement that, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

Medium Risk Requirement

A requirement that, if violated, could directly affect the electrical state or the capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or, a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system.

However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk electric system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

Lower Risk Requirement

A requirement that is administrative in nature and a requirement that, if violated, would not be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor and control the bulk electric system; or, a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature.

FERC Violation Risk Factor Guidelines

The SDT also considered consistency with the FERC Violation Risk Factor Guidelines for setting VRFs:[1]

Guideline 1 – Consistency with the Conclusions of the Final Blackout Report

The Commission seeks to ensure that Violation Risk Factors assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System.

In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:[2]

- Emergency operations
- Vegetation management
- Operator personnel training
- Protection systems and their coordination
- Operating tools and backup facilities
- Reactive power and voltage control
- System modeling and data exchange
- Communication protocol and facilities
- Requirements to determine equipment ratings

[1] North American Electric Reliability Corp., 119 FERC ¶ 61,145, order on reh'g and compliance filing, 120 FERC ¶ 61,145 (2007) ("VRF Rehearing Order").
[2] Id. at footnote 15.

- Synchronized data recorders
- Clearer criteria for operationally critical facilities
- Appropriate use of transmission loading relief

Guideline 2 – Consistency within a Reliability Standard
The Commission expects a rational connection between the sub-Requirement Violation Risk Factor assignments and the main Requirement Violation Risk Factor assignment.

Guideline 3 – Consistency among Reliability Standards
The Commission expects the assignment of Violation Risk Factors corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline 4 – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular Violation Risk Factor level conforms to NERC's definition of that risk level.

Guideline 5 – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria – Violation Severity Levels
Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. Each requirement must have at least one VSL. While it is preferable to have four VSLs for each requirement, some requirements do not have multiple "degrees" of noncompliant performance, and may have only one, two, or three VSLs.

Violation severity levels should be based on the guidelines shown in the table below:

Lower	Moderate	High	Severe
Missing a minor element (or a small percentage) of the required performance The performance or product measured has significant value as it almost meets the full intent of the requirement.	Missing at least one significant element (or a moderate percentage) of the required performance. The performance or product measured still has significant value in meeting the intent of the requirement.	Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. The performance or product has limited value in meeting the intent of the requirement.	Missing most or all of the significant elements (or a significant percentage) of the required performance. The performance measured does not meet the intent of the requirement or the product delivered cannot be used in meeting the intent of the requirement.

FERC Order of Violation Severity Levels

FERC's VSL guidelines are presented below, followed by an analysis of whether the VSLs proposed for each requirement in the standard meet the FERC Guidelines for assessing VSLs:

Guideline 1 – Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance

Compare the VSLs to any prior levels of non-compliance and avoid significant changes that may encourage a lower level of compliance than was required when levels of non-compliance were used.

Guideline 2 – Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties

A violation of a "binary" type requirement must be a "Severe" VSL.

Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

Guideline 3 – Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement

VSLs should not expand on what is required in the requirement.

Guideline 4 – Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations

. . . unless otherwise stated in the requirement, each instance of non-compliance with a requirement is a separate violation. Section 4 of the Sanction Guidelines states that assessing penalties on a per violation per day basis is the "default" for penalty calculations.

VRF and VSL Justifications

VRF Justifications – PRC-023-3, R7	
Proposed VRF	**High**
NERC VRF Discussion	A Violation Risk Factor of High is consistent with the NERC VRF definition. Failure by an entity to apply load-responsive protective relay settings in accordance with the proposed standard PRC-025-1, Attachment 1; Relay Settings, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. The unnecessary tripping of protective relays on generators has often been determined to have expanded the scope and/or extended the duration of disturbances of the past 25 years. This was also noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent. This requirement is analogous with the proposed PRC-025-1, Attachment 1, Table 1, Options 14 through 19 for generator interconnection Facility(ies). The loss of the connection between the generator and the Transmission system can directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This requirement is directly related to observations from the NERC Recommendation 8a and US Canada Power System Outage Task Force Recommendation 21a, and is developed explicitly to address those recommendations. A High VRF is consistent with the role that relay loadability played in contributing to the August 14, 2003 Northeast Blackout. Further, this requirement addresses observations from the related reports that a number of generators tripped because of load-responsive protective relays, and establishes criteria recognizing the dynamic performance of generators during stressed system conditions for lines which connect those generators to the transmission system.

VRF Justifications – PRC-023-3, R7	
Proposed VRF	**High**
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Requirements R1, R2, and R8 have similar reliability objectives and are assigned High VRFs.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: No other approved Reliability Standards address similar reliability goals. Requirement R1 of Draft Reliability Standard PRC-025-1 has a similar reliability goal, and is currently assigned a High VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs The proposed VRF is consistent with the NERC definitions of VRFs because as described above the requirement ensures that load-responsive protective relays will not improperly operate during the loading conditions described within the R7 criteria. This requirement if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed requirement does not co-mingle more than one obligation.

Proposed VSLs for PRC-023-3, R7				
R7	**Lower**	**Moderate**	**High**	**Severe**
R7	N/A	N/A	N/A	The responsible entity did not set one of its generator interconnection Facility relays in accordance with the criteria in Attachment C.

VSL Justifications – PRC-023-3, R7	
NERC VSL Guidelines	The NERC VSL guidelines are satisfied by identifying noncompliance based on “pass-fail” or a binary condition. The entity either “applied” or “did not apply” the setting(s) in accordance with PRC-023-3 Attachment C; therefore, the Violation Severity Level must be designated Severe.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new requirement. However, the proposed VSL for Requirement R7 is consistent with the approved VSL for the similar Requirements R1 and R2 within PRC-023-2.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is binary and assigns a “Severe” category for the violation of the requirement. Guideline 2b: The proposed VSL for Requirement R7 does not contain ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding Requirement, R7.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is based on a single violation and not a cumulative number of violations.

VRF Justifications – PRC-023-3, R8	
Proposed VRF	**High**
NERC VRF Discussion	A Violation Risk Factor of High is consistent with the NERC VRF definition. Failure by an entity to apply load-responsive protective relay settings in accordance with the proposed standard PRC-025-1, Attachment 1; Relay Settings, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition. The unnecessary tripping of protective relays on generators has often been determined to have expanded the scope and/or extended the duration of disturbances of the past 25 years. This was also noted to be a serious issue in the August 2003 "blackout" in the northeastern North American continent. This requirement is analogous with the proposed PRC-025-1, Attachment 1, Table 1, Options 7 through 12 for generator interconnection Facility(ies). The loss of the connection between the generator and the Transmission system can directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.
FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report: This requirement is directly related to observations from the NERC Recommendation 8a and US Canada Power System Outage Task Force Recommendation 21a, and is developed explicitly to address those recommendations. A High VRF is consistent with the role that relay loadability played in contributing to the August 14, 2003 Northeast Blackout. Further, this requirement addresses observations from the related reports that a number of generators tripped because of load-responsive protective relays, and establishes criteria recognizing the dynamic performance of generators during stressed system conditions for transformers which connect those generators to the transmission system.

VRF Justifications – PRC-023-3, R8	
Proposed VRF	**High**
FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard: Requirements R1, R2, and R7 have similar reliability objectives and are assigned High VRFs.
FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards: No other approved Reliability Standards address similar reliability goals. Requirement R1 of draft Reliability Standard PRC-025-1 has a similar reliability goal, and is currently assigned a High VRF.
FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs The proposed VRF is consistent with the NERC definitions of VRFs because as described above the requirement ensures that load-responsive protective relays will not improperly operate during the loading conditions described within the R8 criteria. This requirement if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures.
FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation The proposed requirement does not co-mingle more than one obligation.

Proposed VSLs for PRC-023-3, R8				
R8	**Lower**	**Moderate**	**High**	**Severe**
R8	N/A	N/A	N/A	The responsible entity did not set one of its generator step-up transformer relays in accordance with the criteria in Attachment C.

VSL Justifications – PRC-023-3, R8	
NERC VSL Guidelines	The NERC VSL guidelines are satisfied by identifying noncompliance based on “pass-fail” or a binary condition. The entity either “applied” or “did not apply” the setting(s) in accordance with PRC-023-3 Attachment C; therefore, the Violation Severity Level must be designated Severe.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	This is a new requirement. However, the proposed VSL for Requirement R8 is consistent with the approved VSL for the similar Requirements R1 and R2 within PRC-023-2.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The proposed VSL is binary and assigns a “Severe” category for the violation of the requirement. Guideline 2b: The proposed VSL for Requirement R8 does not contain ambiguous language.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL is consistent with the corresponding Requirement, R8.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The proposed VSL is based on a single violation and not a cumulative number of violations.

Standards Announcement

Project 2010-13.2 – Phase 2 of Relay Loadability: Generation
PRC-023-3 & PRC-025-1

Formal Comment Period for PRC-025-1 and PRC-023-3: April 25, 2013 – May 24, 2013

Upcoming:
Successive Ballot and Non-Binding Poll for PRC-025-1: May 15, 2013 – May 24, 2013

Now Available

A 30-day formal comment period is open for **PRC-023-3** – Transmission Relay Loadability and **PRC-025-1** – Generator Relay Loadability through **8 p.m. Eastern on Friday, May 24, 2013**.

Background information for this project can be found on the project page.

Instructions for Commenting

A formal comment period for **PRC-023-3** and **PRC-025-1** is open through **8 p.m. Eastern on Friday, May 24, 2013.** Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller at wendy.muller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

A successive ballot of **PRC-025-1** and non-binding poll of the associated VRFs and VSLs will be conducted from May 15, 2013 through May 24, 2013.

Standards Development Process

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

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

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Name (31 Responses)
Organization (31 Responses)
Group Name (50 Responses)
Lead Contact (50 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (9 Responses)
Comments (50 Responses)
Question 1 (37 Responses)
Question 1 Comments (50 Responses)
Question 2 (33 Responses)
Question 2 Comments (50 Responses)
Question 3 (33 Responses)
Question 3 Comments (50 Responses)
Question 4 (32 Responses)
Question 4 Comments (50 Responses)
Question 5 (39 Responses)
Question 5 Comments (50 Responses)

Texas Reliability Entity
Texas Reliability Entity
NA
NA
No
(1) Texas RE objects to the use of the term Regional Reliability Organization (RRO) in Table 1. RRO is an obsolete term that NERC had been trying to purge from the standards, and we are somewhat alarmed to see it used in a new place in the standards. While we recognize that RRO is defined in the Glossary, it is not in the functional model and, at least in our region, it does not identify any entity and it is ambiguous. We urge you to replace the term RRO with an entity type from the functional model, or to write a description of what is intended without using the term "RRO". (2) Regarding the “Transformers” section on page 7 and footnote 3 on page 10, consider whether it is appropriate to use the “nameplate impedance at the nominal GSU turns ratio” in all instances. In some cases, it is more appropriate to use the calculated (i.e. with compensation) impedance that reflects the lowest value based on the de-energized tap and LTC tap positions for this purpose. (3) For Options 1a, 2a, and 7a, consider using 0.9 per unit instead of 0.95 per unit, because typical disturbance (post-contingency) voltage criterion is 0.9 p.u. (4) Consider clarifying that the Real Power output criteria should be based on the [highest seasonal] MW rating for the applicable unit. There can be significant seasonal variations in MW capabilities for some units. We don’t expect pickup settings to be changed from season to season, so an appropriate year-round setting should be determined and applied. (5) Some transmission systems have steady state stability limits that encroach into the generator capability limits. Consider adding exclusion criteria for these types of scenarios.
Texas RE generally supports this standard as written, other than the use of the term *Regional Reliability Organization* in Table 1 as described above. Our other comments are provided for consideration by the drafting team.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Pamela R. Hunter
Yes

Yes
Yes
Yes
2) We suggest removing Section 3.2.3 and footnote 1. UAT protection is part of the station service system and should not be in this standard. Remove the UAT from Table 1. The UAT relays are not in the category of “all load-responsive protective relays that are affected by increased generator output in response to system disturbances.” The highside overcurrent pickup should not be required to be at 150%. Settings at > & = 115% should be allowed. 3) We believe that the Purpose statement should end "… do not pose a risk of damaging the generator." 4) The protection of the generator should be the paramount concern. All ANSI standards for generator and main power transformer protection should be considered to be the ruling guide for protecting the equipment. The minimum allowable settings provided in the table in the draft standard do not factor using time delays in order to provide adequate protection for generators. 5) The overload relay that protects the generator from overload may also be the relay that protects the GSU from overload. In the exception list of the draft standard, exception bullet #5 should take precedence over exception bullet #6. 6) The protection requirements (exception bullet #5) from the ANSI standards need additional recognition, development, and emphasis in the Exceptions section. As written, it appears to be an afterthought. The ANSI standard for synchronous generator protection should be recognized, respected, and not violated. The Table 1 setting specifications which contradict the ANSI standards should be submissive to the ANSI standards and itemized in the exception criteria. Consider removing “extremely” from the "extremely inverse time" description as various vendors call the varying inverse time curve by different names. 7) The generator overload protection exception added to Draft 3 for extremely inverse characteristics (fifth exception bullet) is an improvement, but the term “full-load current” needs clarification. Is this the current at normal full-load turbine output and typical PF, the value determined from the generator nameplate MVA at rated voltage, or is it the base or top (no fans, no oil circulation) MVA rating of the GSU? 8) The wording in the sixth exception bullet of the Exceptions section is too vague. How much of an overload is considered an overload? Many vendor relay curves do not provide characteristics showing the value of current that will time out in 15 minutes. It may be difficult to prove a setting to provide 15 minute delay. Existing relays in service do not have the ability to be set by this criterion. 9) The Exceptions section seems to state that the exceptions are allowed only during start up and when off line, which is unacceptable. The exceptions should be allowed at all times. 10) To meet the requirements of table 1 for non-51 relays (distance relays set at approximately 180% of generator MVA) and meet our protection philosopy objectives, we would have to install many new relays for overload protection. 11) Determination of the pickup of the distance relays is too complicated. The calculated impedance should be based on generator nameplate MVA and pf only. The requirements make what should be a simple calculation based on generator electrical characteristics into one that will require the relay engineer to find test MW data is not readily unavailable. 12) PRC-025 should be revised to "grandfather" existing protection settings that have been proven in practice for many decades not to prematurely remove equipment from service. 13) The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, whose tripping would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings for retoration purposes. 14) Voltage-restrained overcurrent relays are notorious for not having a predictable operation time under fault conditions. If they are included in the types of equipment that mis-operated in the August 2003 blackout, they should be required to be replaced with another relay type rather than requiring that the settings be relaxed to the degree specified in the draft standard. 15) A High VRF and a Severe VSL seems overly harsh given the compliance feasibility uncertainties. 16) Which UATs are proposed to be included, if any, is confusing. Suggest adding diagrams to the reference document. 17) During the webinar there were three slides related to the different trans to Gen interconnections and who is responsible for what; suggest adding and or clarifying these in the reference documents.
Vladimir Stanisic
AESI Inc.
na

na
Yes
No
The team is commended for an extensive effort to provide high level of detail through numerous relay setting examples summarized in Table 1 and elaborated in the document PRC_025_1_Guidlines_and_Technical_Basis_Draft_3_2013_04_24_Redline.pdf. Nonetheless, the following points may need further attention: 1. The settings derived by simulations versus the settings derived by manual calculations are noticeably different, the latter being repeatedly much more conservative (e.g. 8c: 6.6 A pu versus 8a: 9.5 A pu), exposing generators to a higher risk of overloading. It would be expected that the results of manual calculations and simulations would yield closer values, at least for most of typical configurations. It appears that underlying assumptions used in the calculations and simulations may need to be fine-tuned. For example, is it realistic to have field forcing producing 1.5 pu MVAR output and at the same time generator bus voltage at 0.95 pu. 2. The settings derived by manual calculations are such the generators are exposed to a higher risk of overloading: • Example 1a – 21 protection would operate only when unit loading exceeds approx. 280% (at rated power factor). • Example 2a – 51V protection pickup is set at equivalent of approx. 170% loading. Taking into account that overcurrent relays actually react when current exceeds 1.5 pickup setting, equivalent loading on the unit would have to exceed 250% before timing is initiated. Depending on the relay characteristic, time delay can be significant. 3. C37.102 states that acceptable settings for 21 function are 150% to 200% (at rated power factor). These values should guide the requirements of this standard. 4. The Table specifies pickup setting criteria. It remains unclear when are the relays allowed to trip. 5. Examples 7a, b, c, seem to be duplication of 1a, b, c. 6. The following comment from the Guidelines document is not clear: ====== Options 7a and 10, Table 1 – Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for generator bus voltage, ***however due to the presence synchronous generator 0.95 per unit bus voltage will be used as (Vgen)***?: ==========
No
Please see comments on Question 2.
Yes
Yes
This draft of the standard uses 0.85 pu transmission system voltage as a benchmark for determining the settings. The latest version of PRC-024-1 defines post-disturbance voltage profile where the system voltage is below 0.85 pu up to 3 seconds. Is there a need to take that into consideration for this standard.
Northeast Power Coordinating Council
Guy Zito
Yes
In PRC-023-3, add “Each” to the beginning of R8.
Pepco Holdings Inc. & Afffiliates
David Thorne
No
1) The inclusion of Requirements R7 and R8 and the entire Table 1 from PRC-025-1 overly complicates PRC-023-3. In addition, inclusion of these Table 1 requirements without the corresponding Guidelines and Technical Basis document produced for PRC-025 makes the application

of Table 1 in PRC-023 difficult, if not impossible. The intent of the original PRC-023 was to apply to owners of load responsive relays (whether they be TO's or GO's) that are applied on BES transmission circuits and BES power transformers. The new PRC-025 standard should apply to owners of load responsive relays (whether they be TO's or GO's) that are applied on BES generators, GSUs, UAT's and Generator Interconnection Facilities. In a good faith effort to provide a bright line between the two standards, the new PRC-023-3 standard became overly complicated and extremely confusing. It would seem that instead of adding PRC-025 requirements to PRC-023, it would be much simpler to just add Transmission Owners to the Applicability Entities section of PRC-025. The Applicable Facilities section of each standard should identify that any load responsive relay (whether they are owned by GO's or TO's) installed on these types of facilities must comply with the respective requirements of that standard. If this were done then the original PRC-023 could be revised to exclude relays installed on generators, GSU's, UAT's and Generator Interconnection Facilities, as they will be covered by PRC-025. PRC-023 would apply solely to owners of load responsive relays (whether they be TO's or GO's) that are applied on BES transmission circuits and BES power transformers. 2) It is unnecessary to remove Criterion 6 from PRC-023-3 as it represents an acceptable alternative to the methods offered in PRC-025. When load responsive relays are set on transmission line terminals connected to generation stations remote from load in accordance with Criterion 6 of PRC-023 (230% of aggregate generation nameplate capability) the resulting setting provides sufficient margin to accommodate acceptable loadability. This criterion has been successfully used for years and has gone through the full standards development process and been vetted as an acceptable alternative. Consider the example calculation for Option 14a in PRC-025. From Equation 112 the apparent primary impedance seen by the relay on the high side of the GSU is 74.3 ohms primary at an angle of 52.77 degrees. Now assume the 230% method from PRC-023 Criterion 6 was used instead. The new apparent power would be 2.3 x (767.6 MW + j 475.6 MVAR) = 2.3 x 903 MVA =2076.9 MVA at an angle of 31.8 degrees. Using Equation 112 the apparent primary impedance would be 41.4 ohms at 31.8 degrees. From Equation 115 the setting required to satisfy Option 14a criteria from PRC-025 would be 15.283 ohms sec = 76.42 ohms primary at 85 degrees. The reach of this relay along the 31.8 degree load angle would be 76.42 x Cos (85 – 31.8) = 45.77 ohms primary. Since this is greater than the 41.4 ohm setting resulting from Criterion 6 of PRC-023, the PRC-023 Criterion is slightly more conservative, requiring a slightly smaller relay reach than Option 14a. As such, both methods should be considered equally effective in ensuring relay loadability.
No
For the PRC-025 standard the inclusion of Table 1 along with the Figures and Example Calculations in the Guidelines and Technical Basis document clearly identifies the proposed setting criteria. However, the inclusion of Table 1 in PRC-023 overly complicates the scope of PRC-023, and without inclusion of the corresponding Guidelines and Technical Basis document makes application of Table 1 criteria difficult. We feel strongly that all references to load responsive relays applied on generators, GSU's, UAT's and Generation Interconnection Facilities (including Table 1 and Requirements R7 and R8) should be eliminated from PRC-023 as they are already adequately covered in PRC-025. Transmission Owners that own load responsive relays on those types of facilities should be included as an Applicable Entity under PRC-025. (See comments submitted for Question 1).
No
1) The new term "Generator Interconnection Facilities" is not defined in the NERC Glossary of terms, nor is it defined in the body of the standard. It is defined in the Guidelines and Technical Basis document; however, we feel this term needs to be defined within the body of the standard itself. Perhaps a footnote similar to that used to define Unit Auxiliary Transformers would be appropriate. We would suggest the same definition used in the Guidelines and Technical Basis document be inserted: "Generator interconnection Facility(ies) consists of Elements between the generator step-up transformer and the interface with the portion of the bulk Electric System (BES) where Transmission Owners take over the ownership." 2) In Figures 4 and 5 the CT's supplying the 21, 51V-R and 51V-C relays connected to the generator(s) look like they are connected to the generator neutral. To make it clear that they are supplied from CT's connected in the phase leads, a phase to neutral transition symbol (ref Fig 7.4 in IEEE C37.102) should be used to indicate the CTs are located above the neutral connection point. 3) In Figure 5 there is a 51 relay shown connected to the 22kV bus leads supplying the generator on the left hand side of the drawing. This 51 relay is not reverenced, or used, in any of the options and therefore should be removed from the drawing. 4) Options 14a, 14b, 15a, 15b, 16a and 16b all use an MVAR value equal to 120% of the aggregate generation MW value, instead of the

150% value used when the relays are located on the generator side of the GSU transformer. Presumably this is to account for the I squared Xt MVAR loss consumed in the GSU transformer. However, there is no mention of this fact in the Guidelines and Technical Basis document. To avoid confusion as to why different MVAR criteria are used, supporting technical justification / explanation should be offered in the document. 5) The example calculations for Options 4 and 10 are combined as a single identical set of calculations. This calculation is appropriate for Option 10 but not for Option 4. Referring to Figure 5, the 21 relays for Option 4 are shown connected to each individual generator. Also the 20MVAR static compensation source is connected upstream of each generator relay. As such, the 21 relay on each individual generator (Option 4) will only see the MW and MVAR flows from a single generator, not the aggregate of all the generation plus the 20MAR reactive source. A separate calculation for Option 4 should be developed. For that Option 4 case the single generator apparent power (assuming three generators of equal size) would be 102/3 = 34 MW and 63.2/3 = 21 MVAR, which is 40 MVA for each generator. 6) The example calculations for Option 5 appear to be incorrect. Again referring to Figure 5, the 51V-R relays for Option 5 are shown connected to each individual generator. Also the 20MVAR static compensation source is connected upstream of each generator relay. As such, the 51V-R relay on each individual generator (Option 5) will only see the MW and MVAR flows from a single generator, not the aggregate of all the generation plus the 20MAR reactive source. As such the 51V-R relay should be set to 130% of the maximum MVA rating of that individual generator. Again assuming three units of equal size, each generator would be rated 40MVA and therefore the 51V-R relay should be set to not operate below 1.3 x 40 = 52 MVA 7) The example calculations for Options 7a, 10, 8a, 9a, 11, and 12 illustrate a mixture of synchronous and asynchronous generators. However, there is no corresponding one-line drawing which corresponds to these examples. Because of this, it is difficult visualize the topology of this arrangement and where the corresponding relays would be located. If the SDT wishes to provide an example calculation where there is a mix of synchronous and asynchronous generation then we would suggest an additional figure be added (Figure 6) which would illustrate this type of connection.
Yes
No
FirstEnergy
Doug Hohlbaugh
No
FirstEnergy (FE) appreciates the attempt to develop a bright-line method but feel the approach taken is over complicating the standards. FE believes that the changes made to PRC-023 with the inclusion of requirements R7 and R8 and the associated Attachment C cause unnecessary confusion. FE proposes that the team remove R7, R8 and Attachment C from PRC-023 and retain a modified version of PRC-023, R1 item 6. Further, as supported in our comments below, we encourage the team to limit the applicability of PRC-023 to the TO and DP and the applicability of PRC-025 to the GO. FE believes it is imperative for NERC to develop its standards in a consistent approach in regard to terminology that is deemed “transmission” and those deemed “generation”. We are concerned that the proposed changes to PRC-023 and PRC-025 overly complicate what most in industry already understand to be “transmission” and “generation” facilities. For example, NERC recently proposed errata changes to PRC-004 and PRC-005 to clarify that for a GO the requirements of those standards extend not only to protection systems associated with the generating facility or station itself, but also to any protection systems associated with the generator interconnection facility. It’s difficult to understand why PRC-004 and PRC-005 seem to have clear TO and GO boundaries when it comes to reporting relay misoperations and performing relay maintenance, yet when ensuring relay loadability requirements are met things all of a sudden become much more complicated. To date, generation interconnection facility(ies) as used in NERC standards are generator owner assets, “generator lead”, operated at transmission voltage levels. However, if the generator lead happens to be owned by a transmission owner, then it’s understood simply to be a transmission line or transmission facility. The two relay loadability standards should maintain this same simplicity and PRC-023 should apply only to TO/DP and PRC-025 to the GO. We suggest that the team take this opportunity to introduce a formally defined NERC Glossary Term for generator interconnection facility. During the recent webinar the

team spent a fair amount of time indicating that when evaluating a generator interconnection facility(ies) as shown in Figure 1 and Figure 2 that it essentially comes down to the relay owner when determining which standard (PRC-023 or PRC-025) is applicable. The team indicated that if the GO owns the relay for line breaker(s) at Bus A then PRC-025 applies, but if the DP/TO owns the relay then PRC-023 applies. The team further described that the GO was left in PRC-023 to handle a situation where they may own relaying for line breaker(s) on networked transmission lines as shown in Figure 3. The team also cited they retained the GO for this situation to avoid a potential "registration tension". The perceived need for the GO in standard PRC-023 calls into question the facility rating for the network transmission line as established under FAC-008-3. NERC standards must maintain consistent philosophies in terminology throughout all standards and cover the most common system configurations. Any unique situations will need to be dealt with on a case by case basis between asset owners. Additionally, NERC drafting teams should not be writing standards to cover one-off configurations simply to address potential entity registration concerns. While FE strongly objects to the use of R7, R8 and Attachment C in PRC-023, if the team does not agree with our proposal to remove the GO completely from PRC-023 then as an alternate approach we support comments filed by Pepco Holdings, Inc. – PHI which suggesting adding the TO/DP to PRC-025 and removing R7, R8 and Attachment C from PRC-023. Either approach (FE's or PHI's) requires retaining item 6 of R1 in PRC-023. In summary, for PRC-023, FE proposes the following: 1.) Remove the Generator Owner applicability 2.) Remove Requirements 7 and 8 since they will be included in PRC-025 3.) Remove Attachment C 4.) Change Requirement 1 Criteria #6 to read as follows: "Set transmission line relays applied on transmission lines connected to generation stations remote to load directional towards the generator so they do not operate at or below 115% of the rating of the generator as calculated according to applicable NERC standards." Although not our preferred option, we also recommend the team considered the suggestion by PHI that would add the TO as an applicable entity to PRC-025 while also removing PRC-023 R7, R8 and Attachment C.
No
As stated above (Question 1) FE does not support the inclusion of Attachment C in PRC-023. See question 1 for more information. From a technical standpoint, we support Table 1 of PRC-025.
Yes
Yes
Yes
FE believes that that the term "generator interconnection Facility" should be a NERC defined term in the Glossary since it is used in other standards, ie, PRC-005, or at the very least, be defined within the standard(s). This term is only defined in the Guidelines and Technical Basis. In the Guidelines and Technical Basis, Figure 2 has a typo on the 3rd sentence and should read as follows: If the Distribution Provider or Transmission Owner owns these relay, they are responsible for them under PRC-023.
John Yale
Chelan County PUD
none
none
No
It seems that GSU and UAT would be subject to PRC-023 and PRC-025. It would be cleaner if one standard applied to GSU and UAT and the other to the transmission circuits.
Yes
Yes
Yes

1. Please, reconsider the applicaiton to small units that are "black start" or auxiliary units in a BES plant. Application of these requirements to a small (750kW) hydro unit that is black start is problamatic particularly due to the age of many of these units. It is difficult to see where loss of a unit of small size would impact the BES during this type of event. Please, consider a minimum size threshold for units where these requirements would be applicable. Perhaps 20MW as is used in the BES definition would be appropirate. Consider also an exclusion for a small unit, say less than 5MW, that is part of an aggregate plant of larger units that exceeds the 75MW plant threshold. An example is our 750kW hydro unit that is in the plant with ten 25MW units. It seems excessive to apply this to the 750kW unit. 2. UATs should be dropped from the standard. The Application Guidelines state that the reliability objective of PRC-025 is to cover, “all load-responsive protective relays that are affected by increased generator output in response to system disturbances,” but the relays of UATs are not in this category. A disturbance on the HV system would not affect the real or reactive power draws of auxiliary loads, and it was stated in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of ’03. UATs are stated later in the Application Guidelines to have been included to satisfy a FERC directive (Order No. 733, paragraph 104), but such a move nonetheless appears to be incorrect, particularly in light of NERC’s recent emphasis on the cost justification of reliability standards. 3. Clarify UAT and station service transformers. Footnote 1 says "Loss of these transformers will result in removing the generator from service." Does that mean it only applies to SS transformers that loss of will remove a unit from service? What about provisions for backup, multiple transformers and busses? Consider an hydro plant with 4 sation service busses and 12 generating units. Would this standard apply to all? This is very different from thermal stations where a unit would have a dedicated transformer that without its power the unit will trip. Consider liminting this only to transformers where loss would cause a direct trip of a BES unit, or eleminiate UAT ans SS transformers completely per comment 2. 4. The generator overload protection exception added to Draft 3 for extremely inverse characteristics (5th bull-dot) is a major improvement, but the term “full-load current” needs clarification. Is this the current at normal full-load turbine output and typical PF, or the value determined from the generator nameplate MVA at rated voltage, or the base (no fans, no oil circulation) rating of the GSU, or FERC hydro nameplate criteria at best gate? 5. PRC-025 should be revised to grandfather existing major equipment, similar to the approach recently used for PRC-024. It may not always be possible to develop PRC-025-conforming means of protection without replacing GSUs or UATs; and, in the absence of any compensation to the owner, it would be inappropriate to outlaw equipment that was acceptable under the rules in effect at the time it was installed. 6. Deeming any and all violations of this standard to have a high violation risk factor and a severe violation severity level seems overly harsh, given the compliance feasibility uncertainties expressed above. Consider a VSL based on the size of the generating unit or amount of generation that would be lost if the standard were not properly applied. A 20MVA unit would have a much lower impact on the reliability of the BES than a 500MW unit.
Barbara Kedrowski
Wisconsin Electric
Wisconsin Electric
Barb Kedrowski
Agree
NAGF
Operational Compliance
Ed Croft
Yes
Content is good. However - the two standards should refer to EXACTLY the same table of Relay Loadability Evaluation Criteria with EXACTLY the SAME OPTION #s for each Relay Type/Application.

The table could stand on its own and each record be labeled with PRC-025 and/or PRC-023 applicability (new column(s)).
Yes
But...see comments for Question #1.
Yes
See comments for Question #1. In addition, Figures 1,2 and 3 could be clarified by 1) labelling the Generator Interconnection Facility with a pointer and parentheses, 2) include table with columns for Relay Owners, Function of Owner and Applicable Standard. This way, a quick glance at the figure can clarify which standard is applicable (rather than having to decipher the caption).
Yes
Editorial note: To aid with distinguishing between options: underline the words "is necessary" and "is not necessary" for "Implementation Date" columns.
Clem Cassmeyer
Western Farmers Electric Cooperative
Western Farmers Electric Cooperative
Caleb Muckala
Agree
Western Farmers Electric Cooperative
No
See comments to question 5
No
See comments to question 5
Yes
Many generation Facilities, that are part of the Bulk Electric System, became commercial in the 1950's, 1960's, 1970's, 1980's and 1990's. These Facilities should be Grandfathered in. Many of these units, although reliable, it may not be cost effective to obtain compliance with PRC-025-1. Many of these Facilities would be forced to either: (1) implement very expensive upgrades to existing equipment, (2) replace existing equipment, (3) retire the Facility. It's my opinion this is not consistent with the economic rational NERC is attempting to achieve. Secondly, the Violation Risk Factor of High, seems extreme because several other standards address generator reliability (Under-frequency, Misoperations, Protection System Maintenance and Testing, Generator Verification). These standards, have resulted in many generation Facilities having undergone relay coordination studies to prevent an occurrence similar to the 2003 "blackout."
Michael Mayer
Delmarva Power & Light Company
Pepco Holdings Inc & Affiliates
David Thorne
Agree
Pepco Holdings Inc. & Affiliates
NICOLE BUCKMAN
Atlantic City Electric Company
Pepco Holdings inc. & Affiliates
David Thorne

Agree
Pepco Holdings Inc. and Affiliates
MRO NERC Standards Review Forum
Russel Mountjoy
Yes
Yes
Yes
Yes
The NSRF remains concerned that the proposed calculations for the distance relays will adversely affect reliability of the BES by requiring generators to pull back distance reaches too far which could lead to reduced rely coverage (at least for backup relaying) or longer delays for coordination. Some sample calculations performed by NSRF members show that distance reaches need to be pulled back more than 30%. The NSRF members believe that this is most likely due to the more conservative relay load limit angle calculations at 30 degrees rather than former MidContinent Area Power Pool (MAPP) criteria which used line Maximum Torque Angle calculations which typically averaged near 70 – 85 degrees. Sample MAPP Relay Load Limit Calculation: (0.85*kV)^2 / (Z1max*cos(max torque angle – line power factor angle) NSRF sample calculations show that many generators may require 21 distance setting changes based upon this proposed standard, potentially resulting in potential reductions of relay backup coverage for lines leaving some generating stations. This will put a much higher risk and responsibility on the TO too have extremely reliable protection for the lines. We will no longer be able to trip the generator off in a backup mode if the TO does not clear the phase fault at end of line. This appears to conflict with R1, unless the standard is mandating the installation of additional equipment such as redundant relays systems to maintain reliable fault protection. The NSRF would ask the NERC Standard drafting team to work with NSRF members to help verify the basis for the new calculations and if this does in fact reduce relay coverage or require entities to install additional relaying to maintain system reliability as mandated in R1.
Mark Yerger
Potomac Electric Power Company
Pepco Holdings, Inc & Affiliates
David Thorne
Agree
Pepco Holdings Inc. and Affiliates
Jonathan Meyer
Idaho Power Company
n/a
n/a

Yes
Yes
Yes
Yes
No
Alice Ireland
Xcel Energy
n/a
Alice Ireland
Yes
No
For 51 relay that is installed on the high side of GSU, we suggest it should be an acceptable option if the 51 relay setting meets R1 Criteria 11.
No
In the last paragraph on page 19 of the clean version of the PRC-025-1 Guidelines and Technical Basis, the following sentence appears: "Phase time overcurrent relays applied to the UAT that act to trip the generator directly or via lockout or auxiliary tripping relay are to be compliant with the relay setting criteria in this standard." This typically would be the case for UAT's connected to the generator bus. However, for system connected auxiliary transformers as shown in Fig 6 on page 20, it is very unlikely that the time overcurrent relays protecting the system connected transformers will act to trip the generator directly or via lockout as this is a different zone of protection and to do so might result in an unnecessary challenge of the unit's overspeed protection. Instead, these overcurrent relays will trip the source breakers feeding the system connected auxiliary transformer but will not act to directly trip the generator. The generator will ultimately trip because of the resultant loss of power to the auxiliary system when the source breakers feeding the auxiliary transformer are tripped. The loss of auxiliary power will likely result in some form of a turbine/prime move trip and the generator breaker will be tripped open once power output drops to zero. In this manner, unit overspeed protection is not unnecessarily challenged. It seems that the quoted sentence on page 19 only serves to confuse the matter. If the goal of this setting requirement is to not to have the plant trip due to a loss of auxiliary power based on overly conservative setting of overcurrent relays, it is immaterial whether the overcurrent relays act to trip the generator directly or via lockout or auxiliary tripping relay or if the plant ultimately trips because a loss of auxiliary power caused by overcurrent relays opening source breakers to the system connected auxiliary transformer. We recommend the quoted sentence be stricken from the guideline and technical basis document.
Yes
Yes
1) Applicability: In the applicability sections, we suggest you replace the phrase "BES generating unit or generating plant" with "BES generating unit or BES generating plant" to be more clear. 2) M1: We recommend you add “simulation results” as acceptable evidence in Measure M1. (reason: Some people may choose to do PRC023 check in the CAPE simulation.)
Michael Falvo
Independent Electricity System Operator
NPCC

Michael Falvo
Yes
Yes
Yes
Yes
No
PacifiCorp
Ryan Millard
Yes
Yes
Yes
Yes
No
Wryan Feil
Northeast Utilities
Wryan Feil
Wryan Feil
Yes
Yes
Yes
Yes
No
SERC Protection and Controls Subcommittee
David Greene
Yes
No
There is a discrepancy between the relay functions listed in PRC-023-3 Attachment A and those identified in PRC-023-3 Attachment C Table 1 and PRC-025-1 Attachment 1 Table 1. PRC-023-3 Attachment A includes under 1.6, “Phase overcurrent supervisory elements (i.e., phase fault

detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications." These schemes are not accounted for in the Table 1 of either proposed standard. Given these schemes are required to meet loadability criteria on transmission lines not meeting the "generator interconnection facility" designation (i.e. networked lines), the exclusion of the schemes from generator loadability criteria creates confusion. Loadability criteria should be included for "Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications" in Table 1 of both PRC-023-3 and PRC-025-1.
Yes
Yes
Yes
There were three one-line reference drawings described on the webinar. Suggest adding text to these reference drawings or add descriptive wording in reference documents to better explain responsibilities of relay owners for these various configurations. On the webinar there were repetitive questions about these configurations so this would indicate confusion. Also, would suggest adding another drawing to illustrate when you have a generating station where the GO owns GSU relays and the TO owns relays between the GSU and switchyard to clarify that the TO is only responsible for R7 in PRC023-3 and not R8 since the GSU relays are a GO asset.
Nazra Gladu
Manitoba Hydro
Manitoba Hydro
Nazra Gladu
Yes
Yes
(1) Manitoba Hydro suggests eliminating Table 1 from one of the standards and referencing it in the other standard, since both PRC-023-3 and PRC-025-1 are already very lengthy standards.
Yes
Yes
Yes
(1) Section 3.1.1, PRC-025-01 - the repeated word "Facilities" seems unnecessary. For clarity, remove the last instance of the word "Facilities" in the statement: "Generator Owner that applies load-responsive protective relays at the terminals of Facilities listed in 3.2, Facilities." (2) Section 3.2 - it would be useful to add criteria that define which generator units should be included as associated with the BES. Alternatively, should this standard refer to the BES definition for which generator units in this standard will apply to? (3) Section 3.2.5 - It is unclear what elements should be included in this section - Collector lines only? What size (MVA) of generating source that the collector line has to be on to qualify as one of these elements? (4) Implementation Plan, PRC-023-3 - it would be helpful to include the implementation plan within the standard. (5) PRC-023-3, Purpose - suggest re-wording to the following "…not interfere with a system operators ability to take remedial action to protect system reliability….". (6) PRC-023-3, Purpose - capitalize "system operator" because it appears in the Glossary of Terms. (7) PRC-023-3, Applicability, Functional Entity - capitalize "protection system" because it appears in the Glossary of Terms. (8) PRC-023-3, 4.2.1.3 - 'BES' should be written Bulk Electric System (BES) since it is the first appearance of the word. (9) PRC-023-3, 4.2.3.1 - should Transmission lines be written "Transmission lines (and paths)"? (10) PRC-023-3, R1, 4 - capitalize the words "power transfer capability" because it appears in the Glossary of Terms. (11) PRC-023 and PRC-025 - capitalize the words "transmission lines" throughout the document(s). (12) PRC-023 and

PRC-025, D. Compliance 1.1 - the paraphrased definition of 'Compliance Enforcement Authority' from the Rules of Procedure is not the standard language for this section. Is there a reason that the standard CEA language is not being used? (13) PRC-023-3 — Attachment B, Circuits to Evaluate - replace the acronym "BES" with the words "Bulk Electric System". (14) PRC-023-3 — Attachment B, Criteria, B2 - write out the words for "IROL" then use the acronym thereafter. (15) PRC-023-3 — Attachment C - use the acronym "RRO" after the first instance of the words "Regional Reliability Organization". (16) PRC-025-1 – Attachment 1: Relay Settings - use the acronym "RRO" after the first instance of the words "Regional Reliability Organization".
Anthony Jablonski
ReliabilityFirst
ReliabilityFirst
Anthony Jablonski
Yes
Yes
No
1) There appears to be an error in the Guidelines and Technical Basis document on page 23 for option 15b. It indicates that the Reactive Power output that equates 120% of the maximum gross Mvar output whereas Table 1 states 100%. 2) A statement should be inserted that the iterative calculation stopped because the change was < 1%. This applies to options 1b & 7b on page 31 and option 2b on page 38. Also, if an entity knows the resistive and reactive impedances of the transformer, the entity could directly calculate the low-side GSU voltage from the high-side voltage, the per unit current through the GSU and the full impedance of the transformer.
Yes
Yes
1) In Attachment 1, it is not clear that the fifth bulleted exception regarding protection systems that detect generator overloads needs or should be as specific as to cite the 7 seconds at 218% of full-load current operating point or characteristic curve. Typically for a fault right on the generator terminals, the current decays in a couple of seconds to around full load current even with the AVR in service. Even during field forcing, it is more likely that the field overcurrent relay would operate rather than a generator overload relay. Therefore, the exclusion does not appear to be needed. If the exclusion is needed, it is recommended that the exclusion be stated in a more general way such as the following: Protection systems that detect generator overloads that are designed to coordinate with the generator short-time capability by utilizing a relay characteristic set to operate no faster than the capability curve and supervised to prevent operation below 115% of full-load current. 2) The word 'Each' appears to be missing in Requirement R8 of PRC-023-3. 'Each' should be inserted at the beginning of the requirement before Transmission Owner and Distribution Provider. 3) Since there are cases where redundant UATs that allow a generator to continue to remain in service when one UAT trips, this may be rationale to revise 3.2.3 of the Applicability section to indicate exclusion for these configurations. Alternatively, it could be addressed in the Guidelines and Technical Basis document. 4) The Regional Reliability Organization (RRO) is referenced within both standards and it was ReliabilityFirst's understanding that the term RRO was to be removed from all the standards. In Order 693, Paragraphs 146-148 and paragraph 157 state "The Commission adopts the NOPR proposal to eliminate references to the regional reliability organization as a responsible entity in the Reliability Standards. We conclude that this approach is appropriate because, as explained in the NOPR, such entities are not users, owners or operators of the Bulk-Power System. NERC indicates that it can remove such references, except that the Regional Entity should be identified as the compliance monitor where appropriate." ReliabilityFirst suggests replacing the RRO with the Planning Coordinator (PC) or other registered function the SDT determines to have the wide area view and be responsible for determining what these settings and or values should be.
David Jendras

Ameren
Ameren Compliance
Eric Scott
No
(1) For consistency, we believe that PRC-023-3 requirement R7 should only apply at 200kV and above. Therefore, we request the SDT to change 4.2.3.1 to 'Transmission lines operated at 200kV and above that are used…"
No
(1) We ask the SDT to clarify that 'nameplate MVA rating' means the 'generator nameplate MVA rating'. Therefore we request that the SDT either add a statement "Unless otherwise stated, 'nameplate MVA rating' means the 'generator nameplate MVA rating' throughout Table 1", or insert 'generator' before 'nameplate MVA rating'.
No
(1) We request the SDT to add a multiple winding transformer example. We recommend that the SDT include an example with equally rated CTGs connected to equally rated dual secondary transformer windings stepping up to a single high voltage winding, because it is commonly used. (2) The MW capability reported to the Transmission Planner changes by a very small amount from time to time. As written we believe that this could trigger a significant amount of documentation. We request the SDT to show in your example (s) how an increased margin would address such a small change (e.g. a 2% increase from the originally documented value) before triggering such a review. (3) On page 2 of the Guidelines and Technical Basis document, we ask the SDT to delete 'Generator Owner' from the last sentence of Figure 2 caption.
Yes
Yes
(1) The generator overload protection exception on page 8 for "extremely inverse characteristics" (5th bullet-dot) is a major improvement, but we believe that the term "full-load current" needs clarification. We ask the SDT, is this current at 100% of the gross MW capability reported to the TP, or the value determined from the generator nameplate MVA at rated voltage, or the base (no fans, no oil circulation) rating of the GSU or the smallest of these? (2) We believe that Blackstart Resources should be excluded because there is no technical basis for including them. On the contrary, it is more important to assure Blackstart Resources are adequately protected and available for restoration in the extremely unlikely event that a wide-area blackout occurs. Also, we believe that there is no evidence that the tripping of a Blackstart Resources has contributed to widespread outages. In our experience, these resources are below the 20MVA threshold and even if they were on-line and tripped their impact to the BES are minimal. (3) In addition to our comments, we also agree with the SERC Protection & Control Subcommittee (PCS) comments and include them by reference.
Thomas Foltz
American Electric Power
Does Not Apply
Does Not Apply
No
AEP believes that both documents would benefit from the inclusion of a simplified GO/TO interface diagram showing the overlap and applicability of the two standards within the opening section of each standard. Clarity needs to be provided to PRC-023-3 regarding the proper consideration of GO-owned transmission line protection systems. It must be understood that for load responsive relays subject to R7 and R8, the responsibility to perform loadability evaluations is on whoever is the owner of the Protection System. Regarding PRC-023-3, it is unclear exactly what facilities are included in the term "BES Generating Unit". It is requested that this be clarified. AEP also requests clarification on the voltage levels applicable to Regarding PRC-023-3 R7. Section 4.2.3.1 currently applies to "transmission lines" which implies that all voltage levels would be subject to this requirement. It is requested that this be revised to clarify exactly what voltage applies.

No
PRC-023-3 must be clear in stating that, if a Transmission or Distribution line used solely to export energy directly from the GU has its own circuit breaker, then the existing R1 through R5 criteria should be applied based on the rating of the line. PRC-023-3 appears to exclude relays directional toward the Generating Unit. For example, if you attempt to evaluate loadability for two-terminal 345kV line to a windfarm, it appears to be applicable to both PRC-023-3 4.2.1 and 4.2.3. This would make it difficult to determine what Transmission lines are subject to evaluation and which requirement to apply, R1 or R7. Based on the current draft, it is not clear what criteria set to apply. The criteria in Table 1 is based on Generator's power while the criteria in Requirement 1 is based on circuit ratings. It needs to be clarified which criteria set is to be applied. A second example is in a situation when a loadability evaluation is needed for a two-terminal line that is definitely not applicable to 4.2.1., but *is* applicable to 4.2.3. The intent of having two standards appears to be to have the relays on the Generating Unit end owned by the GO, set according to criteria R1 in PRC-025-1; and to have the relays on Generating Unit end owned by the TO, set according to criteria R7 in PRC-023-3. In this example, there would appear to be no criteria required to set relays on the end external to the Generating Unit, for relays owned by either the GO or TO. Clarification is needed to define responsibility based on Protection System ownership as well as to clearly convey the applicability of remote protection systems.
Yes
No
Regarding PRC-025-1: While AEP appreciates the factors considered by the drafting team when developing the proposed implementation plan for PRC-025-1, the plan as proposed will not afford adequate time for large Generator Owners to comply with the standards. AEP has 119 generating units and 2 wind farms that are applicable to PRC-025-1. The resources needed to evaluate the generating units for compliance with PRC-025-1 and PRC-023-3 will also be engaged in implementing the new NERC standards PRC-019-1 and PRC-024-1. For these reasons, AEP believes a phased implementation plan for PRC-025-1 is more appropriate. Such a plan would require entities to show that a minimum percentage of their applicable relays are compliant within a specified time frame. For example: * Entities shall demonstrate that 30% of their applicable load-responsive protective relays are fully compliant with R1 within 48 months of the effective date of this standard. * Entities shall demonstrate that 60% of their applicable load-responsive protective relays are fully compliant with R1 within 60 months of the effective date of this standard. * Entities shall demonstrate that 100% of their applicable load-responsive protective relays are fully compliant with R1 within 72 months of the effective date of this standard. Regarding PRC-023-3: The proposed revision could significantly impact Transmission Owners. Additional research is being conducted within AEP Transmission to determine the extent of that impact. It is possible that the proposed implementation plan would not provide adequate time to achieve compliance with the standard if it is determined to impact a high volume of facilities. Additional research will be needed before a recommendation be made on the extent the additional time required. It is still unclear when TOs, GOs and DPs will be required to complete loadability evaluations for any circuits below 200kV included by the Planning Coordinator per Attachment B. It is understood that we will have 39 months to apply the initial list. There is confusion however on whether or not the 39 months applies to new inclusions to the list. AEP requests that this time frame be clarified and included in the standard, as it is information needed to maintain compliance on an ongoing basis.
Yes
System fed auxiliary transformers whose loss would not result in an instantaneous generating unit trip, and for which operators would have opportunity to reconfigure the plant auxiliary load before a unit trip occurs, should be excluded from this standard. However, if the SDT intends the standard to be applicable to all system fed auxiliary transformers, we recommend removing the text "…that trips the generator either directly or via an interposing/lockout relay" from the standard. This statement is similar to language that entities have used to exclude system fed auxiliary transformers that initiate a process shutdown trip from the scope of other NERC PRC standards. During a disturbance in which system voltage becomes depressed, the generator will respond by increasing excitation in an effort to compensate for the voltage loss. This will result in the generator terminal voltage being greater than the system voltage. For this reason, AEP recommends that settings for applicable relays installed on the generator side of the GSU be based on a generator bus voltage of 1.0 per unit at the generator

terminals, rather than a generator bus voltage calculated from 0.85/0.95 per unit of the GSU high-side nominal voltage.
Chris Mattson
Tacoma Power
Tacoma Power
Chris Mattson
Yes
Yes
Yes
Yes
Yes
Comments 1-4 below pertain to PRC-025-1. 1. Referring to Attachment 1, are phase fault detectors used in current-based local breaker failure schemes excluded from PRC-025-1? 2. Referring to Attachment 1, Footnote 3 still has the terms "no-load tap changers (NLTC)" and "on-load tap changers (OLTC)." 3. Referring to page 22 of 68 of the redlined Guidelines and Technical Basis, the first paragraph after "Generator Interconnection Facilities (Synchronous Generators) Phase Distance Relays – Directional Toward Transmission System (21) (Options 14a and 14b)," change "…for these relay…" to "…for these relays…" (There are also other instances of this issue.) 4. Referring to page 20 of 68 of the redlined Guidelines and Technical Basis, would the UATs shown in Figure 6 necessarily be applicable to PRC-025-1? It seems that phase time overcurrent relays applied to UATs like these might not "act to trip the generator directly or via lockout or auxiliary tripping relay." Comments 5-8 below pertain to PRC-023-3. 5. Referring to Attachment C, why are only two of the bulleted exceptions shown in PRC-025-1 Attachment 1 brought over? 6. Referring to page 12 of 13 of the redlined Implementation Plan, change "…were added to address to situations…" to "…were added to address situations…" 7. Referring to page 13 of 13 of the redlined Implementation Plan, last row in the table, are references to R7 supposed to be references to R8? Additionally, change "…equally and efficient…" to "…equally efficient…"
RoLynda Shumpert
South Carolina Electric and Gas
Self
RoLynda Shumpert
Yes
Yes
Yes
Yes
No
Rick Terrill
Luminant Generation
Luminant Generation
Rick Terrill

No
Luminant recommends the following: (1) Load responsive relays identified in PRC-025-1 and 023-3 connected on generator breaker(s) at the GSU high side and are primarily used for backup of failed transmission line relaying shall use options in Attachment C (PRC-023-3) and Attachment 1 (PRC-025-1). (2) Load responsive relays identified in PRC-023-3 and connected on the high side of the GSU that are primarily used for transmission line protection shall use the existing criteria in PRC-023-2, Requirements R1 through R6. The above recommendations can be done by adding diagrams in PRC-023-3 and clarifying Figures 1, 2, and 3 in PRC-025-1.
No
Luminant disagrees that the criterion for setting load responsive relays is clear because of the bright line is vague. Luminant recommends that each standard be clear in addressing the relay setting criteria by its primary application.
No
Figures 1, 2, and 3 do not provide a sufficient bright line between the application of PRC-025-1 and PRC-023-3 for setting criterion. Luminant recommends that additional information be added that identifies that a load responsive relays located on the transmission line breaker at Bus A and are primarily installed for transmission line protection use PRC-023-3 criterion Requirements R1 through R6 (regardless of the number of generators or transmission lines connected to Bus A). Load responsive relays located on the high side of the GSU and are primarily used for failed transmission line protection should use PRC-023-3 (Attachment C) or PRC-025 (Table 1).
No
Luminant recommends that the phrase “where relay replacement is not required” and “where relay replacement is required” add the word removal; i.e., “replacement or removal”.
No
David Gordon
Massachusetts Municipal Wholesale Electric Company
n/a
n/a
Agree
North American Generator Forum
Mark Stein
Tri-State G&T
Tri-State Generation and Transmission Assoc
Mark Stein
No
The generator overload protection exception added to Draft 3 for extremely inverse characteristics is a major improvement, but the term “full-load current” needs clarification. Is this the current at normal full-load turbine output and typical PF, or the value determined from the generator nameplate MVA at rated voltage, or the base (no fans, no oil circulation) rating of the GSU?
Yes

1. UATs should be dropped from the standard. The Application Guidelines state that the reliability objective of PRC-025 is to cover, “all load-responsive protective relays that are affected by increased generator output in response to system disturbances,” but the relays of UATs are not in this category. A disturbance on the HV system would not affect the real or reactive power draws of auxiliary loads, and it was stated in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of ’03. UATs are stated later in the Application Guidelines to have been included to satisfy a FERC directive (Order No. 733, paragraph 104), but such a move nonetheless appears to be incorrect, particularly in light of NERC’s recent emphasis on the cost justification of reliability standards. 2. PRC-025 should be revised to grandfather existing major equipment, similar to the approach recently used for PRC-024. It may not always be possible to develop PRC-025-conforming means of protection without replacing GSUs or UATs; and, in the absence of any compensation to the owner, it would be inappropriate to outlaw equipment that was acceptable under the rules in effect at the time it was installed. 3. The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which NERC requirements have already eliminated any economic rationale for having black-start facilities. 4. Regarding in particular voltage-restrained overcurrent relays, this type of device is notorious for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be set as high as specified in the draft standard.
PPL NERC Registered Affiliates
Brent Ingebrigtson
Yes
Yes
No
See Comments for Question #5
Yes
Yes
: The PPL NERC Registered Affiliates reiterate their concern in regards to the following comments. The Application Guidelines state that the reliability objective of PRC-025 is to cover, “all load-responsive protective relays that are affected by increased generator output in response to system disturbances.” Unit Auxiliary Transformers (UAT’s) are not in this category and should therefore be excluded from the Applicability of the Standard in Section 3.2.3. The point was made in the 5/15/13 webinar that a decrease in HV system voltage would affect the plant MV voltage as well, causing a proportional increase in current (at constant power draw by plant auxiliary loads) and thereby potentially tripping UAT loadability relays. Reduction in frequency during disturbances will strongly reduce the power draw of pumps and fans, however, so MV current may actually drop despite the HV voltage reduction being experienced. This point of view is supported by the statement in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of ’03, so extending PRC-025 applicability to UATs provides only a hypothetical benefit that has not been observed (or has in fact been disproved) in practice. The PPL NERC Registered Affiliates again state that Facilities’ UATs in Section 3.2.3 do not belong in this standard as no technical justification has been provided. An investigation and evaluation of the protection systems for unit auxiliary transformers and the UAT’s lack of impact on generator loadability should be considered by the SDT. A cost-benefit analysis for generator UATs should be performed to demonstrate that net benefits will result from any such standard before it is proposed. Without such an analysis, the standard may result in costs without a sufficient reliability benefit and may in some cases actually lessen reliability (see item 5 below). 2.) The generator overload protection exception added to Draft 3 for “extremely inverse characteristics” (5th bull-dot) is a major improvement, but the term “full-load

current" needs clarification The PPL NERC Registered Affiliates suggest that the SDT state in the Guidelines and Technical Basis that "full-load current" is understood to be the generator nameplate MVA at rated voltage 3.) The overload protection exception added to Draft 3 for "extremely inverse characteristics" should be applied for UAT's as well if eliminating UAT's in its entirety (per comment #1 above) does not prove feasible. 4.) The PPL NERC Registered Affiliates reiterate their concern in regards to the following comments. PRC-025 should be revised to grandfather existing major equipment, similar to the approach recently used for PRC-024. It may not always be possible to develop PRC-025-conforming means of protection without replacing GSUs or UATs; and, in the absence of any compensation to the owner, it would be inappropriate to outlaw equipment that was acceptable under the rules in effect at the time it was installed. 5.) The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which NERC requirements have already eliminated any economic rationale for having black-start facilities. Given the numerous CIP standards in effect to afford protection to the critical BS restoration facilities, it would be contradictory to impose a standard that could potentially increase risk of damage to a BlackStart Generator by forcing the BS facility to ride through the disturbance. If that disturbance is a precursor to a blackout, then having BS Resource unavailable to facilitate system restoration would defeat the purpose of designating it as a Blackstart Resource. 6.) The PPL NERC Registered Affiliates reiterate their concern in regards to the following comments. Regarding in particular voltage-restrained overcurrent relays, this type of device is known for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be set as high as specified in the draft standard. 7.) Deeming any and all violations of this standard to have a high violation risk factor and a severe violation severity level seems overly harsh, given the compliance feasibility uncertainties expressed above. 8.) The compliance uncertainties expressed above also promote the use of risk based compliance approach rather than a zero tolerance policy. Other standards in development (CIP V5 standards) no longer dictate a zero tolerance policy. This concept should be applied to the PRC-025 standard to align with the direction NERC standard development is progressing.
North American Generator Forum Standards Review Team
Patrick Brown
No
See comments to question 5 below
Yes
1. UATs should be dropped from the standard. The Application Guidelines state that the reliability objective of PRC-025 is to cover, "all load-responsive protective relays that are affected by increased generator output in response to system disturbances," but the relays of UATs are not in this category. A disturbance on the HV system would not affect the real or reactive power draws of auxiliary loads, and it was stated in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of '03. UATs are stated later in the Application Guidelines to have been included to satisfy a FERC directive (Order No. 733, paragraph 104), but such a move nonetheless appears to be incorrect, particularly in light of NERC's recent emphasis on the cost justification of reliability standards. 2. The generator overload protection exception added to Draft 3 for extremely inverse characteristics (5th bull-dot) is a major improvement, but the term "full-load current" needs clarification. Is this the current at normal full-load turbine output and typical PF, or the value determined from the generator nameplate MVA at rated voltage, or the base (no fans, no oil circulation) rating of the GSU? 3. The exception of comment #2 above, which is presently limited to generator overloads, could be applied for UATs as well if eliminating this equipment in its entirety (per comment #1 above) does not prove feasible. 4. PRC-025 should be revised to grandfather existing major equipment, similar to the approach recently used for PRC-024. It may not always be possible to develop PRC-025-conforming means of protection

without replacing GSUs or UATs; and, in the absence of any compensation to the owner, it would be inappropriate to outlaw equipment that was acceptable under the rules in effect at the time it was installed. 5. The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which NERC requirements have already eliminated any economic rationale for having black-start facilities. 6. Regarding in particular voltage-restrained overcurrent relays, this type of device is notorious for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be set as high as specified in the draft standard. 7. Deeming any and all violations of this standard to have a high violation risk factor and a severe violation severity level seems overly harsh, given the compliance feasibility uncertainties expressed above.
Michelle R. D'Antuono
Ingleside Cogeneration LP
Individual -- Ingleside Cogeneration LP
Michelle R. D'Antuono
No
Even though the language in both standards draws a technically accurate bright line, Ingleside Cogeneration believes that the addition of the generator relay criteria to PRC-023-3 is confusing at best. It appears that the issue has to do with the ownership of the relays. In some cases the DP and/or the TO owns a load responsive relay that is protecting generation equipment. Conversely, some GOs own load responsive relays that protect transmission equipment. If the concept of the two standards is that PRC-023-3 applies to transmission-related relays and PRC-025-1 applies to generation-related relays, than the owner of the relay is not a gating factor. This means that the applicability table for both standards would include DPs, GOs, and TOs. There would be no repeated criteria between the standards in this arrangement – and less confusing in our view.
Yes
Yes
No
Ingleside Cogeneration LP does not agree with the 100% compliance approach that the drafting team has taken in regard to PRC-025-1. Although FERC Order 733 is cited multiple times as the reliability need, there are real dollars that the industry will need to expend to analyze and replace load responsive relays for generators of any size. We do not read Order 733 the same way – and FERC has accepted exceptions for low-impact facilities in the past.
Yes
In the previous posting, the project team requested our estimated compliance costs and comments on the RSAW. Both of these projects are components of risk-based compliance – which Ingleside Cogeneration LP fully supports. However, it appears that these are not considerations at all in the latest postings. We are not sure what has changed in the intellectual basis of risk-based compliance, but it seems we have taken a step backwards. The rationale for far too many of the project team's consideration of comments was that FERC Order 733 mandated some action. Since FERC has been generally supportive of the risk-based initiative, this type of response is inconsistent with their position in our view.
Western Area Power Administration
Lloyd A. Linke
Yes
Yes

Recommend adding reference to Table 1 - Options 7, 8, 9, 10, 11, 12 – Relay Type back to options 1, 2, 3, 4, 5, 6 for applications on the generator side of the GSU. The language and reference used in the Relay Type column for Options 1-6 added clarity and should be mirrored in Options 7-12.
Yes
No
Brenda Hampton
Luminant Energy Company LLC
Luminant
Brenda Hampton
Agree
Luminant Generation Company LLC
No
See Luminant Generation Company LLC comments.
No
See Luminant Generation Company LLC comments.
No
See Luminant Generation Company LLC comments.
No
See Luminant Generation Company LLC comments.
No
John Bee
Exelon and its affiliates
NA
NA
The Constellation Energy Nuclear Generation (CENG) NERC Registered Affiliates reiterate their concern in regards to the following comments. The Application Guidelines state that the reliability objective of PRC-025 is to cover, “all load-responsive protective relays that are affected by increased generator output in response to system disturbances.” Section 3.2.3 of PRC-025-1 requires clarification simply because the Unit Auxiliary Transformers (UAT’s) are not necessarily directly connected to the generator, but there are indirect link to the generator operation. The UAT’s are ok to be included to the applicability of this standard, but section 3.2.3 could use more detailed explanation. Moreover, the webinar on 5/15/13 pointed out that a decrease in HV system voltage would affect the plant MV voltage as well, causing a proportional increase in current (at constant power draw by plant auxiliary loads) and thereby potentially tripping UAT loadability relays. Reduction in frequency during disturbances will strongly reduce the power drawn of pumps and fans, however, so MV current may actually drop despite the HV voltage reduction being experienced. This point of view is supported by the statement in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of ’03, so extending PRC-025 applicability to UATs provides only a hypothetical benefit that has not been observed (or has in fact been disproved) in practice. CENG state that Facilities, UAT’s in Section 3.2.3 is appropriate to include it, but there need to be a specific explanation as to the affect of MW due to grid disturbance affect the generator output. An investigation and evaluation of the protection systems for unit auxiliary transformers and the UAT’s lack of impact on generator loadability should be considered.

Daniel Duff
Liberty Electric Power LLC
none
none
Agree
Generator Forum SDT, as submitted by Patrick Brown, Essential Power
No
Oliver Burke
Entergy Services, Inc. (Transmission)
Entergy Services, Inc. (Transmission Owner)
Oliver Burke
Yes
Yes
No
The Guidelines are still not clear about what to do with start-up transformers when used in lieu of the UATs (Unit Auxiliary Transformer).
Yes
Yes
The implementation plan may be challenging to meet and an alternative implementation plan may need to be provided based on the population of load-responsive protective relays determined affected by this standard and the subset of which that will require replacement relays. Additional resources will be required to (1) determine the population of load-responsive relays at each generating station, (2) determine the settings of the existing load-responsive relays, (3) calculate load-responsive relay settings per the reliability standard, (4) compare the existing load-responsive relay settings to the calculated load-responsive relay settings to determine the population which are acceptable as-is, the population that require a settings change, and the population that requires replacement, (5) schedule the population of load-responsive relays for settings change, (6) order replacement load-responsive relays for the population determined incapable of meeting the reliability standard and schedule relay replacement. The resulting calculations and set-point datasheets will form the basis for the load-responsive relay settings and evidence for meeting the standard's requirements.
Dominion
Randi Heise
Yes
Dominion agrees that the addition of requirements in PRC-023-3, R7 and R8 strengthens the bright line between the two standards. However, we do not agree with use of the term "Transmission' in 4.2.3.1 as it is our position that it does not conform with the intent of the term as defined in the NERC Glossary of Terms. We therefore suggest the sentence be revised to read "Lines that are used solely to export energy directly from a BES generating unit or generating plant to the network."
No
Dominion believes that the appropriate designation of "Real Power output" is the generator nameplate rating however Dominion does recognize that the addition of "gross" prior to MW is an improvement

to the table wording.
Yes
Yes
Yes
PRC-025 -1 Requirement 1: remove the following words: "…while maintaining reliable fault protection." It is not possible for entities to measure or prove this statement. The wording, "while maintaining reliable fault protection", is also included in the Introduction section of PRC-025-1 Guidelines and Technical Basis. The inclusion "describes that the Generator Owner is to comply with this standard while achieving its desired protection goals." Dominion believes that the Generator Owner understands the compliance obligation based upon the requirements of the standards and that the inclusion of the referenced language should be excluded based on the inability of the entity to measure or provide evidence of maintaining reliable fault protection. PRC-025-1: Redline - Page 6 of 18 Table of Compliance Elements; An indication of Lower VSL. Moderate VSL or High VSL needs to be determined with regard to R1. Dominion disagrees with the "all or nothing" approach to VSLs. PRC-023-3 Implementation plan; Redline Pages 3-6, R1-R6 the Requirement wording (in the Applicability column) does not exactly match the Requirement wording in the standard. Dominion suggests correcting the wording to match the Standard as written. PRC-025-1 @ figure 3 – Dominion does not necessarily agree that these lines are part of networked transmission and therefore would not be considered as generator interconnection Facilities. Dominion believes the designation of the lines should be based on registration of the asset owner and will be providing supporting comments in response to the FERC NOPR in docket # RM12-16-000.
Chantel Haswell
Public Service Enterprise Group
PSEG
Chantel Haswell
No
For UATs per PRC-025-1, that are energized from the system (as opposed to from the GSU), the SDT seems to assumes that no TO or DP owns the load responsive relays for these UATs. Has that been verified by the SDT?
Yes
The SDT needs to confirm that UATs that are energized from the system (not the GSU) at high-side voltages that are below 100 kV are part of the BES before imposing standards on UAT load-responsive relay settings.
Duke Energy
Michael Lowman
Yes
Yes
No
Examples of calculations are helpful. However, more details on the root of the calculations are needed. Exclusively calculating values on a per unit basis would add more clarity.
No
Duke Energy schedules some of its generating units on a 24 month cycle for minor outages and a 96 month cycle for major outages. This would make the current Implementation Plan very expensive and

difficult to comply with if relay replacements are required. [Duke Energy suggests a 48 month and 96 month Implementation Plan. This would allow for the industry to use existing outage schedules, keeping overall costs at a minimum.]
No
Bret Galbraith
Seminole Electric Cooperative Inc.
Seminole Electric Cooperative, Inc.
N/A
Yes
Seminole Electric reasons that the NERC SDT has not provided sufficient evidence to warrant a High VRF and a Severe VSL for penalties associated with proposed Standard PRC-025-1.
Russ Schneider
Flathead Electric Cooperative
N/A
N/A
No
it is not clear to me how this would impact very small dispersed generators.
Yes
Do not support including Elements utilized in the aggregation of dispersed power producing resources. This seems to have the potential to rope very small generators into significant compliance burdens for very little reliability benefit.
Santee Cooper
Terry L. Blackwell
Yes
Unit Auxiliary Transformers (UATs) should be removed from this standard (Facilities Section 3.2.3). The purpose of this standard is “To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage.” The intent as stated in the Application Guidelines is to pertain to relays that “are affected by increased generator output in response to system disturbances.” UATs do not fit this criteria. Addressing generating plant unit auxiliary transformers does not have to translate into creating a standard requirement for that equipment. An investigation and evaluation of the protection system for unit auxiliary transformers should be considered by the standard drafting team and deemed to be not related to generator loadability and fulfill the FERC order to address the subject.
Robert Rhodes
Southwest Power Pool

N/A
N/A
Yes
Yes
Yes
Yes
Yes
For the sake of clarity, I would suggest adding the phrase 'to the generator' at the end of the Purpose of PRC-025-1. This is implied in the existing language but it wouldn't hurt to add this and specifically indicate what damage you're referring to. For consistency within the requirements and between the requirement and corresponding measure in this situation, please add 'Each' at the beginning of Requirement R8. This makes R8 consistent with the rest of the requirements and with Measure M8.
JEA
Tom McElhinney
No
While it has been demonstrated in the 2003 blackout that a small percentage of generating units did trip off line prematurely due to conservative setting of generator protection systems, no evidence has been provided that transformer tripping contributed to the cause of the generation outages. The sole purpose as stated by the SDT for including transformers is a directive from FERC. We believe that there should be some evidence as to the benefit of preforming protection modifications to transformers and that they should not simply be included until a study can be performed to show the cost benefit analysis and therefore recommend that transformers be excluded during this phase and be incorporated into a phase III. If transformers are to be included, an exception should be provided to allow the start-up transformer to be used to provide auxiliary power in case of failure of the auxiliary transformer. BES reliability is better served by allowing this exception (which will occur very infrequently) than to keep the generating unit off line for fear of being out of compliance with a standard.
No
Considering that applying new settings and testing will require a major outage, we believe that 48 months is not a sufficient time frame for full implementation when existing equipment can be used and relay replacement is not required. We recommend 72 months be allowed even in the case where existing equipment can be used. It may take a year or more to perform the calculations and evaluated equipment and then another 5 years for a major planned outage to occur.
Yes
We would like to see modifications to violation severity levels. While we recognize the SDT is following NERC binary guidelines "pass/fail", this needs to be improved. The idea that either they "applied" or "did not apply" settings must result in a "severe" violation level does not match the reality that missing 10 out of 20 poses a greater risk to the BES than 1 out of 100.
DTE Electric
Kent Kujala
Agree
No
Comments: The distinction is not clear between these two standards regarding generator owner

relays that look toward the transmission system. Perhaps specifying the application location of the relay (CT and PT inputs) would help in clarifying the differences
No
Comments: Suggest that allowing 72 months to become 100% compliant for both 4a and 4b would better align with the unmonitored protective relay maximum maintenance interval of 6 years specified in PRC-005-2. In this way, relay setting changes or replacements could be accommodated during normal scheduled relay maintenance. Also, 48 months could be difficult to achieve for a company with a large generation fleet.
Bonneville Power Administration
Jamison Dye
No
The requirements for generator interconnection facilities in PRC-023-3 apply to Transmission Owner's (and Distribution Provider's , and the requirements for generator interconnection facilities in PRC-025-1 apply to Generation Owner's. BPA believes that putting requirements for the generator interconnection facilities in two separate standards and making the applicability of the standards different is confusing and unnecessary. BPA recommends that all interconnection facilities, regardless of ownership, should be covered within one standard to provide uniformity in the application of settings for interconnection facilities.
No
Example: A 230kV line that is connected between a substation Terminal and a Generating station. (Comment 1) This circuit fits under 4.2.3 of PRC-023-3, so it is subject to Requirement 7. The circuit also fits under 4.2.1, so it is subject to Requirements R1 throughR5. BPA believes it should only be subject to R1 throughR5 or R7, not both. (Comment 2) R7 requires that the load responsive relays be set in accordance with PRC-023-3, Attachment C. BPA would like to point out that the phase distance relays at the substation terminal looking toward the generation are not covered by Attachment C and believes this creates a problem as it makes it impossible for these relays to be set in accordance with Attachment C. The same problem also exists for relays at the terminal of the generator step up (GSU) transformer looking toward the generation, recognizing that this is not a normal application. Based on these issues, BPA believes Attachment C should address all relays, not just those looking towards the Transmission system.
No
While the Guidelines and Technical Basis provides useful information, BPA is concerned that this document will not be approved by FERC as part of the standard and thus the standard must be capable of standing on its own. For this reason, BPA requests that clarification provided in the Guidelines and Technical Basis document be included into the standard specifically in regards to 'generator interconnection facilities'.
Yes
Yes
Comments: (1) The use of the term generation interconnection facility without an official definition of the term is concerning to BPA. BPA believes that this term may have different meanings between entities. For example, the entire Bulk Electric System (BES) together with all distribution systems could be considered to be a generation interconnection facility because the purpose of the BES and distribution systems is to interconnect generation to the end user (load). Only under the Guidelines and Technical Basis is a description of what a generator interconnection facility found.BPA is concerned with this approach as it does not give an official definition, and this document is not part of the standard. Additionally, BPA believes the description of generator interconnection facility given in the Guidelines and Technical Basis creates problems. The description provided is that the generation interconnection facility consists of elements between the generator step up transformer (GSU) and the interface with the portion of the BES where the Transmission Owner (TO) takes over the

ownership. In many cases the TO owns the line that connects to the generator step up (GSU) transformer and there are no elements between the GSU and the TO. According to this description there is no generation interconnection facility. Due to the ownership arrangements of transmission, generation, and their interconnection facilities throughout the country are highly variable, BPA believes it is not suitable to develop a definition of generation interconnection facilities based on ownership. Such a definition may reflect the ownership arrangements within a particular region while it does not take into account various other arrangements that may exist. BPA recommends for the drafting team to provide a definition of generation interconnection facility that takes into account the various ownership situations that may exist. (2) BPA believes the use of the word associated in the purpose statement of PRC-025-1 as well as in Section 3.2 Facilities is too vague and recommends this term be changed to “whose function is the protection of generation Facilities…” in the purpose statement and Section 3.2 be rewritten to read “3.2 Facilities: The following Bulk Electric System Elements, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:”
Tennessee Valley Authority
Dennis Chastain
TVA electric generators segment agrees with comments submitted by the North American Generator Forum (NAGF).
Yes
Yes
No
Yes
Is the intent of this standard to identify the lines in their normal configuration and not for contingency events? For example, referring to Figure 3 from the Webinar, if a line is lost, causing the system configuration to change to what is shown in Figure 1, does this mean that the configuration then is considered to fall under R7?
ACES Standards Collaborators
Jason Marshall
No
There is definitely much clearer delineation between what is required in PRC-023 by the Transmission Owner and Distribution Provider and in PRC-025 by the Generation Owner for generator step up transformers, generators, auxiliary transformers and generator interconnection facilities. However, PRC-023 still has other requirements that are applicable to Generators Owners that do not make sense, create compliance risks and, thus, detract from reliability by distracting the Generator Owner from value added reliability activities. For example, PRC-023 R1 is still applicable to the Generation Owner and it should not be. A Generation Owner does not own transmission beyond the generator interconnection facility. This is recognized in Project 2010-07 Generator Requirements at the Transmission Interface and NERC’s work surrounding the GO/TO and GOP/TOP registration issues. If a Generator Owner owned transmission beyond the generator interconnection facility, they would be registered as a Transmission Owner. Thus, the Generator Owner will be stuck essentially going through a registration exercise for every compliance activity to prove that the requirements do not apply because they do not own transmission facilities. Other requirements in PRC-023 that require removal of Generator Owner include R2, R3, R4, and R5. Until these removals occur, we will not be able to support the standard.
Yes
The table is much clearer than in past versions. However, we do recommend one minor additional change. The option numbers should be reset to 1 for every application and relay type combination since they are truly options within those combinations. Otherwise, a reader may be believe they have 19 options and only have to pick one relay type and application to apply.

Yes
We agree with the 48-month and 72-month implementation plan for PRC-025 and R7 and R8 in PRC-023. However, we believe the implementation plan for PRC-023 as a whole is confusing. Since PRC-023-2 has a staggered implementation plan that is still has not fully been implemented, we recommend laying out a graphical timeline or a Gantt chart that compares PRC-023-2 implementation to that of PRC-023-3.
Yes
(1) We are not convinced that applicability of PRC-023 R7 and R8 to a Distribution Provider is necessary. It would be unusual for a generator that meets BES definition criteria and compliance registry criteria to be connected to a Distribution Provider. Both criteria require a single generator to be 20 MVA or a plant site to be 75 MVA. From a practical perspective, this could actually be a detriment to reliability by distracting the Distribution Provider from reliability activities because they have to focus on documenting that they do not have any applicable generators connected. How does including the Distribution Provider as an applicable entity benefit reliability? (2) The High VRFs for PRC-023 R7 and R8 and PRC-25 R1 and R2 are inconsistent with established NERC criteria. In order to meet the High criteria, a single violation of the requirement "could directly cause or contribute to bulk electric instability, separation or a cascading sequence of failures." A single failure to have a relay set to avoid loadability concerns on a single generator could not lead to instability, separation or cascading without violating other standards. For example, TOP-004-2 R2 already require N-1 operation so a single generator tripping due to relay loadability issues would require at least two standards requirements violations. This cannot be viewed as "directly" causing. (3) We believe the VSLs for PRC-023 R7 and R8 and PRC-25 R1 and R2 are written inconsistent FERC guideline 3 which states that the VSL cannot change the requirement. The plain language of the requirements is written in a plural format as though the requirement considers all relays are considered simultaneously. The VSLs are written such that each relay that is not set appropriately is a separate violation. The VSLs, in essence, change the requirements. For example, the Requirement for PRC-023 R7, states "shall set their load responsive relays," while the VSL essentially modifies the requirement to state "shall set each load responsive relay." We recommend modifying the VSL to be in better alignment with the requirement. (4) The wording in the second sentence of the second paragraph in PRC-023 Attachment C needs to be fixed. There seems to be an extra "Facilities." (5) RRO is used throughout both standards. It should be Regional Entity, as stated in NERC's legal memorandum on the "Use of 'Regional Reliability Organization'…" The memo states that in general, drafting teams can replace "RRO" with "RE," provided the functions being performed by the RE are related to their delegated duties. Reliability Standards that refer to REs are legally binding on the REs by operation of Rule 100 of NERC's Rules of Procedure and by the delegation agreements that NERC has entered into with each RE. (6) Please strike "other entity as specified by the Regional Reliability Organization (RRO)" that is used throughout Attachment C in PRC-023 and Attachment 1 in PRC-025. It creates compliance uncertainty and provides the Regional Entity far too much discretion. If the purpose is an attempt to document from other standards where the nameplate rating is communicating, we suggest that the drafting team perform a search of the other standards and explicitly document the entities. Otherwise, the Regional Entity, as the standard is worded, could simply decide to move the dates. FERC has ordered NERC to remove regional discretion from standards development, such as the revision of the BES definition. (7) We appreciate the relay elements that are identified for exclusion in PRC-023 Attachment C. However, we believe that the exclusion should be identified explicitly in Attachment A as well. Attachment A is referenced in applicability section. We are concerned since attachment C is not referenced in the applicability section that exclusion of the relay elements could be lost. (8) We disagree with the applicability of 3.2.5. We not understand how applicability to a distribution collector system for dispersed generation benefits reliability. If a subset of generators in the dispersed generation site trip, it will be a small amount of MWs lost that would not impact the reliability of the Bulk Power System. We can understand inclusion of the main GSU for a large site but not the individual collector elements.
Brett Holland
Kansas City Power and Light
same as individual info
same as individual info

No
We do not think that the Requirements added to the PRC-023-2 are any different than the Requirements in PRC-025-1. We agree that the addition of PRC-025-1 will cause the removal of part 6 of Requirement 1 in PRC-023-2.
No
We do not think that the information that is shown in the Attachment is very easy to understand but the additional information in the Guidelines and Technical Basis section helps to understand what the table is requesting. Please add to the table the examples shown in the Guidelines and Technical Basis or at a minimum refer to the location the example can be found in that document. This will assist in the understanding of the table. In the Guidelines and Technical Basis the calculation the previous value used for MW was based on the PF for Max Generation. In the new example the value of MW used changed why did that value change?
Yes
Yes
Yes
Generators and Generator step up transformers are critical elements of the BES and have very long lead times for replacement or major repair. However, the Transmission Relay load ability standard has less stringent load ability requirements than the Generator load ability standard. Transmission lines are allowed to trip at 150% of four hour rating or 115% of 15 minute rating. We do not understand the newly added portion of the Exceptions of PRC-025-1 why is there only the option of a specific curve type specified for the Generator. There is no exception available for the GSU or Aux Transformers therefore the GSU and Aux transformers that would allow them to be set like large auto transformers it is not our belief that these transformers should be required to be set with more Stringent settings. We believe that these transformers should be set similar to the large auto transformers.

Consideration of Comments

Project 2010-13.2 Phase 2 Relay Loadability: Generation

The Relay Loadability: Generation Drafting Team thanks all commenters who submitted comments on PRC-025-1 and PRC-023-3. These standards were posted for a 30-day public comment period from April 25, 2013 through May 24, 2013. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 51 sets of comments, including comments from approximately 166 different people from approximately 92 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

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

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

Summary of changes (PRC-023-3)

The generator relay loadability standard drafting team ("SDT") has revised the proposed the draft of PRC-023-3 – Transmission Relay Loadability based on stakeholder comments received during its first 30-day formal posting. The following narrative is a summary of the significant improvements made to the standard.

Standard (PRC-023-3)

The SDT, based on industry stakeholder comments, made substantive changes to the PRC-023-3 standard. The chief change was removing the previously proposed Requirement R7 and R8 which applied to the generator interconnection Facility and generator step-up transformer applicable to the Distribution Provider and Transmission Owner. With this change the SDT added the Distribution Provider and Transmission Owner to the applicability of PRC-025-1 and removed the applicability of those lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network from PRC-023 to establish the bright line between standards according to stakeholder comments.

- Applicability
  - Removed references to Requirements R7 and R8

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

- Added the exception to sections 4.2.1.1, 4.2.2.1, and 4.2.2.2 to exclude lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network
    - Removed the sections 4.2.3 and 4.2.4
- Requirements
    - Requirement R1, criterion 6 was removed to comport with the elimination of addressing load-responsive protective relays on lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network
- Measures
    - Removed the proposed Requirement R7
    - Removed the proposed Requirement R8
- Compliance
    - Removed R7 and R8 references
- Violation Severity Levels
    - Removed R7 and R8
- Attachment A
    - Revised criterion 2.4 as "Note Used" since it is no longer needed
- Attachment C
    - Removed due to Requirements R7 and R8 being eliminated

Implementation Plan (PRC-023-3)

- Updated to reflect the transition of PRC-023-3 Requirement R1, Criterion 6 to the proposed PRC-025-1 criterion

VRF/VSL Justifications (PRC-023-3)

No change, not being provided for comment because the SDT is not making substantive changes to the existing requirements. Only references to Requirement R1, criterion 6 were removed

Summary of changes (PRC-025-1)

The generator relay loadability standard drafting team ("SDT") has revised the proposed draft of PRC-025-1 – Generator Relay Loadability during its 30-day formal comment posting of the standard and successive ballot which received 69.23% stakeholder approval. The following narrative is a summary of the significant improvements made to the above standard.

Standard (PRC-025-1)

- Purpose
  - Minor change for clarity
- Applicability
  - Included the Distribution Provider and Transmission Owner
  - Replaced "generator interconnection Facility" with "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant"
- Requirement
  - Added the Distribution Provider and Transmission Owner
- Measures
  - Added the Distribution Provider and Transmission Owner
- Compliance
  - Added the Distribution Provider and Transmission Owner
- Violation Severity Levels
  - Added the Distribution Provider and Transmission Owner
- Attachment 1
  - General text revisions and clarifications
  - Removed the Regional Reliability Organization (RRO) references
  - Added the following elements to Options 15, 16, and 18; "Phase overcurrent supervisory elements (50) associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications – installed on the high-side of the GSU transformer"

Implementation Plan (PRC-025-1)

- The implementation period for applying settings to load-responsive protective relays that do not require replacement or removal changed from 48 months to 60 months
- The implementation period for applying settings to load-responsive protective relays that do require replacement or removal changed from 72 months to 84 months

VRF/VSL Justifications (PRC-25-1)

- Removed references to PRC-023-3.

Index to Questions, Comments, and Responses

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The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Pamela R. Hunter	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				
No additional members listed.													
2.	Group	Guy Zito	Northeast Power Coordinating Council										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York States Reliability Council, LLC	NPCC	10
2.	Helen Lainis	Independent Electricity System Operator	NPCC	2
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5

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

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

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	David Thorne	Pepco Holdings Inc. & Afffiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley	Delmarva Power & Light Company	RFC	1, 3
2.	Alvin Depew	Pepco Holdings Inc.	RFC	1, 3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Smith	FE RBB Voter Seg 1	RFC	1
2.	Larry Raczkowski (proxy for Cindy Stewart)	FE RBB Voter Seg 3	RFC	3
3.	Doug Hohlbaugh	FE RBB Voter Seg 4	RFC	4
4.	Ken Dresner	FE RBB Voter Seg 5	RFC	5
5.	Kevin Query	FE RBB Voter Seg 6	RFC	6
6.	Bill Duge	FE SME - Generation	RFC	5
7.	Brian Orians	FE SME - Generation	RFC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
8.	Rusty Loy	FE SME - Generation	RFC	5									
9.	Jim Detweiler	FE SME - Transmission	RFC	1									
10.	Rich Maxwell	FE SME - Transmission	RFC	1									
5.	Group	Russel Mountjoy	MRO NERC Standards Review Forum	X	X	X	X	X	X				X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Lawrence	ATC	MRO	1
3.	Dan Inman	MPC	MRO	1, 3, 5, 6
4.	Dave Rudolf	BEPC	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	LES	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Joseph DePoorter	MGE	MRO	3, 4, 5, 6
8.	Ken Goldsmith	ALTW	MRO	4
9.	Lee Kittleson	OTP	MRO	1, 3, 4
10.	Mahmood Safi	OPPD	MRO	1, 3, 5, 6
11.	Marie Knox	MISO	MRO	2
12.	Mike Brytowski	GRE	MRO	1, 3, 5, 6
13.	Scott Bos	MPW	MRO	1, 3, 5, 6
14.	Scott Nickels	RPU	MRO	4
15.	Terry Harbour	MEC	MRO	1, 3, 5, 6
16.	Tom Breene	WPS	MRO	3, 4, 5, 6
17.	Tony Eddleman	NPPD	MRO	1, 3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	David Greene	SERC Protection and Controls Subcommittee										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Nauert	Ameren		
2.	Bridget Coffman	Santee Cooper		
3.	Phil Winston	Southern Company		
4.	Joel Masters	SCE&G		
5.	David Greene	SERC RRO		

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
2.	Annette Bannon	PPL Generation LLC on behalf of Supply NERC Registered Affiliates	RFC	5
3.			WECC	5
4.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
5.			NPCC	6
6.			SERC	6
7.			SPP	6
8.			RFC	6
9.			WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Patrick Brown	North American Generator Forum Standards Review Team					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Allen Schriver	NextEra Energy		5
2.	Steve Berger	PPL Susquehanna, LLC		5
3.	Joe Crispino	PSEG Fossil, LLC		5
4.	Pamela Dautel	IPR-GDF Suez Generation NA		5
5.	Dan Duff	Liberty Electric Power		5
6.	Mikhail Falkovich	PSEG		5
7.	Mike Hirst	Cogentrix Energy, LLC		5
8.	Gary Kruempel	MidAmerican Energy Company		5
9.	Katie Legates	American Electric Power		5
10.	Don Lock	PPL Generation, LLC		5
11.	Joe O'Brien	NIPSCO		5
12.	Dana Showalter	e.on		5
13.	William Shultz	Southern Company		5
14.	Mark Young	Tenaska, Inc.		5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Lloyd A. Linke	Western Area Power Administration	X					X				

Additional Member	Additional Organization	Region	Segment Selection

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

1.	Upper Great Plains Region	Western Area Power Administrtion	MRO	1, 6
2.	Rocky Mountain Region	Western Area Power Administrtion	WECC	1, 6
3.	Desert Southwest Region	Western Area Power Administrtion	WECC	1, 6
4.	Sierra Nevada Region	Western Area Power Administrtion	WECC	1, 6
5.	CRSP Management Center	Western Area Power Administrtion	WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Randi Heise	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Connie Lowe	Dominion	MRO	6
2.	Louis Slade	Dominion	RFC	5, 6
3.	Michael Garton	Dominion	NPCC	5, 6
4.	Michael Crowley	Dominion	SERC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Michael Lowman	Duke Energy	X		X		X	X				

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

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Terry L. Blackwell	Santee Cooper	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tom Abrams	Santee Cooper	SERC	1
2.	Bridget Coffman	Santee Cooper	SERC	1
3.	Rene' Free	Santee Cooper	SERC	1
4.	Paul Camilletti	Santee Cooper	SERC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Tom McElhinney	JEA	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson	JEA	FRCC	1
2.	Garry Baker	JEA	FRCC	3
3.	John Babik	JEA	FRCC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Kent Kujala	DTE Electric			X	X	X					

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Eizans		RFC	3, 4, 5
2.	Herring		NPCC	3, 4, 5

15.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dean Bender	Transmission Technical Services	WECC	1
2.	Stephen Enyeart	Customer Service Engineering	WECC	1
3.	Jim Burns	Technical Operations	WECC	1
4.	Sandra Takabayashi	Hydro Projects	WECC	5

16.	Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Daniel McNeely		SERC	1
2.	Ann Tankesley		SERC	1
3.	Lee Thomas		SERC	5
4.	Tom Vandervort		SERC	5
5.	Paul Palmer		SERC	5
6.	Annette Dudley		SERC	5
7.	DeWayne Scott		SERC	1
8.	Ian Grant		SERC	3
9.	David Thompson		SERC	5
10.	Marjorie Parsons		SERC	6

17.	Group	Jason Marshall	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
2.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1
3.	Chris Bradley	Big Rivers Electric Corporation	SERC	
4.	Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
5.	Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5

18.	Individual	Ed Croft	Operational Compliance	X		X		X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
19.	Individual	Ryan Millard	PacifiCorp	X		X		X	X				
20.	Individual	Texas Reliability Entity	Texas Reliability Entity										X
21.	Individual	Vladimir Stanisic	AESI Inc.										
22.	Individual	John Yale	Chelan County PUD	X				X					
23.	Individual	Barbara Kedrowski	Wisconsin Electric			X	X	X					
24.	Individual	Clem Cassmeyer	Western Farmers Electric Cooperative	X				X					
25.	Individual	Michael Mayer	Delmarva Power & Light Company			X							
26.	Individual	NICOLE BUCKMAN	Atlantic City Electric Company			X							
27.	Individual	Mark Yerger	Potomac Electric Power Company			X							
28.	Individual	Jonathan Meyer	Idaho Power Company	X									
29.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
30.	Individual	Michael Falvo	Independent Electricity System Operator		X								
31.	Individual	Wryan Feil	Northeast Utilities	X									
32.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
33.	Individual	Anthony Jablonski	ReliabilityFirst										X
34.	Individual	David Jendras	Ameren	X		X		X	X				
35.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
36.	Individual	Chris Mattson	Tacoma Power	X		X	X	X	X				
37.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
38.	Individual	Rick Terrill	Luminant Generation					X					
39.	Individual	David Gordon	Massachusetts Municipal Wholesale Electric Company					X					
40.	Individual	Mark Stein	Tri-State G&T	X		X		X					
41.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration LP					X					
42.	Individual	Brenda Hampton	Luminant Energy Company LLC						X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
43.	Individual	John Bee	Exelon and its affiliates	X		X		X					
44.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
45.	Individual	Oliver Burke	Entergy Services, Inc. (Transmission)	X		X		X	X				
46.	Individual	Chantel Haswell	Public Service Enterprise Group	X		X		X	X				
47.	Individual	Bret Galbraith	Seminole Electric Cooperative Inc.			X	X	X	X				
48.	Individual	Russ Schneider	Flathead Electric Cooperative			X	X						
49.	Individual	Robert Rhodes	Southwest Power Pool		X								
50.	Individual	Brett Holland	Kansas City Power and Light	X		X		X	X				
51.	Individual	Phil Waudby	Consumers Energy			X	X	X					

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

Summary Consideration: The drafting team thanks you for your support of other industry stakeholder comments. Approximately ten commenters supported four other organization's comments. These comments are too extensive to summarize here and are summarized in the latter questions. Groups supported include Luminant Generation Company, LLC, North American Generator Forum (i.e., Generator Forum SDT and NAGF), Pepco Holdings Inc. & Affiliates, and Western Farmers Electric Cooperative.

Organization	Agree	Supporting Comments of "Entity Name"
DTE Electric	Agree	North American Generator Forum
Wisconsin Electric	Agree	NAGF
Western Farmers Electric Cooperative	Agree	Western Farmers Electric Cooperative
Delmarva Power & Light Company	Agree	Pepco Holdings Inc. & Affiliates
Atlantic City Electric Company	Agree	Pepco Holdings Inc. and Affiliates
Potomac Electric Power Company	Agree	Pepco Holdings Inc. and Affiliates
Massachusetts Municipal Wholesale Electric Company	Agree	North American Generator Forum
Luminant Energy Company	Agree	Luminant Generation Company LLC

Organization	Agree	Supporting Comments of "Entity Name"
LLC		
Liberty Electric Power LLC	Agree	Generator Forum SDT, as submitted by Patrick Brown, Essential Power
Tennessee Valley Authority		TVA electric generators segment agrees with comments submitted by the North American Generator Forum (NAGF).

1. **Do the changes to the proposed PRC-023-2 and PRC-025-1 (listed above) provide a bright line between the two standards? If not, provide specific suggestions to improve or clarify the performance between the standards.**

Summary Consideration: Approximately three comments representing about eight entities agreed that the changes established a bright line; however, the majority comments revealed that industry stakeholders did not agree with the drafting team's proposed changes to the draft PRC-023-3 standard by adding Requirements R7 and R8 to address those load-responsive protective relays that would apply to the Distribution Provider and Transmission Owner. Among the previous additions include, Attachment C and Table 1 which contained the relay setting criteria as defined by the proposed PRC-025-1 standard applicable only to the generator. The drafting team received approximately six comments supported by 35 stakeholders that either said they did not see how the bright line was improved and the proposed Requirements R7 and R8, and Attachment C only added to confusion.

The drafting team agreed with the above comments and decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. In doing so, the generator requirements subject to PRC-023-3 have been removed; however, will be enforceable until the applicable entities become compliant with PRC-025-1, if settings need modifications. The drafting team notes that it is important to recognize that the owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025-1 and owner of load-responsive protective relays network-related Facilities in PRC-023-3 regardless of ownership of the Facilities.

The following discuss other minority comments by stakeholders. There was one comment supported by 11 entities asking the drafting team to define "generation interconnection Facilities." Although this was a minority comment, the drafting team decided this had merit because the phrase was related to the work done under the NERC Project 2009-07 – Requirements at the Generation Interface. Based on this project and industry's understanding the generator interconnection Facility is generally owned by the Generation Owner, the drafting team understood that when incorporating the Distribution Provider and Transmission Owner in PRC-025-1 that the phrase would add confusion; therefore, the drafting team developed alternative phrasing that reads: "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant."

Adding the Distribution Provider and Transmission Owner to the proposed PRC-025-1 standard addressed other minority comments. One commenter noted that the Distribution Provider, Generator Owner, and Transmission Owner should be in both standards. This was resolved addressing the majority comments. Two comments from individual entities noted that it appeared that both the generator step-up (GSU) transformer and the unit auxiliary transformer (UAT) appeared to be in both standards. After review, the drafting team noted that the GSU was applicable to the Distribution Provider and Transmission Owner in PRC-023-3 and the

Generator Owner in PRC-025-1 that own load-responsive protective relays on a GSU Facility; however, what was revealed was the lack of coverage for a UAT that might be served from the Transmission System. This identification provided support in the drafting team's decision and response to comments to remove Requirements R7 and R8 from PRC-023-3 and add the Distribution Provider and Transmission Owner to PRC-025-1 which included the UAT.

The final minority comments were related to applicability. One commenter believed that only Facilities 200 kV and above should apply to the proposed Requirements R7 and R8 in PRC-023-3. The drafting team noted that it would create a gap in the Facilities that would be covered in each standard; however, with the removal of the two proposed requirements this problem no longer exists. About three comments supported by five entities ask for items that were either already in the provided Figures or as asked for more clarity. The drafting team revised Figures 1, 2, 3, and 5 to add clarity.

An individual comment asked for clarity regarding "BES Generation Unit." The drafting team noted that the proposed PRC-025-1 standard is driven by whether or not an individual generating unit or generating plant meets the Bulk Electric System (BES) definition criteria (e.g., single units larger than 20 MVA or a site with an aggregate capacity of 75 MVA or greater). Once the unit or plant is applicable, those Elements found the Applicability section 3.2, Facilities are to be addressed by the loadability criteria of the standard. Last, one commenter asked how very small dispersed generators would be impacted. As mentioned in the previous sentence, small generators are addressed by virtue of the BES definition.

Organization	Yes or No	Question 1 Comment
Pepco Holdings Inc. & Afffiliates	No	1) The inclusion of Requirements R7 and R8 and the entire Table 1 from PRC-025-1 overly complicates PRC-023-3. In addition, inclusion of these Table 1 requirements without the corresponding Guidelines and Technical Basis document produced for PRC-025 makes the application of Table 1 in PRC-023 difficult, if not impossible. The intent of the original PRC-023 was to apply to owners of load responsive relays (whether they be TO's or GO's) that are applied on BES transmission circuits and BES power transformers. The new PRC-025 standard should apply to owners of load responsive relays (whether they be TO's or GO's) that are applied on BES generators, GSUs, UAT's and Generator Interconnection Facilities. In a good faith effort to provide a bright line between the two standards, the new PRC-023-3 standard became overly complicated and extremely confusing. It would seem that instead of adding PRC-025 requirements to PRC-023, it would be much simpler to just add Transmission Owners to the

Organization	Yes or No	Question 1 Comment
		Applicability Entities section of PRC-025. The Applicable Facilities section of each standard should identify that any load responsive relay (whether they are owned by GO's or TO's) installed on these types of facilities must comply with the respective requirements of that standard. If this were done then the original PRC-023 could be revised to exclude relays installed on generators, GSU's, UAT's and Generator Interconnection Facilities, as they will be covered by PRC-025. PRC-023 would apply solely to owners of load responsive relays (whether they be TO's or GO's) that are applied on BES transmission circuits and BES power transformers. 2) It is unnecessary to remove Criterion 6 from PRC-023-3 as it represents an acceptable alternative to the methods offered in PRC-025. When load responsive relays are set on transmission line terminals connected to generation stations remote from load in accordance with Criterion 6 of PRC-023 (230% of aggregate generation nameplate capability) the resulting setting provides sufficient margin to accommodate acceptable loadability. This criterion has been successfully used for years and has gone through the full standards development process and been vetted as an acceptable alternative. Consider the example calculation for Option 14a in PRC-025. From Equation 112 the apparent primary impedance seen by the relay on the high side of the GSU is 74.3 ohms primary at an angle of 52.77 degrees. Now assume the 230% method from PRC-023 Criterion 6 was used instead. The new apparent power would be 2.3 x (767.6 MW + j 475.6 MVAR) = 2.3 x 903 MVA =2076.9 MVA at an angle of 31.8 degrees. Using Equation 112 the apparent primary impedance would be 41.4 ohms at 31.8 degrees. From Equation 115 the setting required to satisfy Option 14a criteria from PRC-025 would be 15.283 ohms sec = 76.42 ohms primary at 85 degrees. The reach of this relay along the 31.8 degree load angle would be 76.42 x Cos (85 - 31.8) = 45.77 ohms primary. Since this is greater than the 41.4 ohm setting resulting from Criterion 6 of PRC-023, the PRC-023 Criterion is slightly more conservative, requiring a slightly smaller relay reach than Option 14a. As such, both methods should be considered equally effective in ensuring relay loadability.

Organization	Yes or No	Question 1 Comment
Response: The drafting team thanks you for your comment and has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, the standard is being revised to exclude the lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network from its Applicability. Also, Requirement R1, Criterion 6 is proposed for removal from the standard, as it addresses those Facilities being excluded from the Applicability. Change made. The drafting team thanks you for your comment and notes that it considered this same concern in past meetings and concluded that the Mega-Watt (MW) value reported to the Transmission Planner was the most practical approach for a basis in determining the required setting(s). The Generator Owner has flexibility in using a more restrictive setting, which would be the case of using the generator name plate. In option 1, for example, the requirement is to use 100% of the reported MW and 150% of the nameplate MW to arrive at the Mvar component of the complex power. The impedance element must be set less than the calculated impedance derived from 115% of the complex power, which is using criteria (1) and (2). The standard allows the applicable entities the flexibility to account for variable changes in the reported MW value and select a setting that best suits their specific operating history or expectation. No change made. Using the reported MW value accounts for environmental conditions that impact the operation of generation units and those units which operate at a level lower than their nameplate rating. This more closely achieves a loadability setting corresponding with the expected performance of the generator during field-forcing. No change made.		
FirstEnergy	No	FirstEnergy (FE) appreciates the attempt to develop a bright-line method but feel the approach taken is over complicating the standards. FE believes that the changes made to PRC-023 with the inclusion of requirements R7 and R8 and the associated Attachment C cause unnecessary confusion. FE proposes that the team remove R7, R8 and Attachment C from PRC-023 and retain a modified version of PRC-023, R1 item 6. Further, as supported in our comments below, we encourage the team to limit the applicability of PRC-023 to the TO and DP and the applicability of PRC-025 to the GO. FE

Organization	Yes or No	Question 1 Comment
		believes it is imperative for NERC to develop its standards in a consistent approach in regard to terminology that is deemed "transmission" and those deemed "generation". We are concerned that the proposed changes to PRC-023 and PRC-025 overly complicate what most in industry already understand to be "transmission" and "generation" facilities. For example, NERC recently proposed errata changes to PRC-004 and PRC-005 to clarify that for a GO the requirements of those standards extend not only to protection systems associated with the generating facility or station itself, but also to any protection systems associated with the generator interconnection facility. It's difficult to understand why PRC-004 and PRC-005 seem to have clear TO and GO boundaries when it comes to reporting relay misoperations and performing relay maintenance, yet when ensuring relay loadability requirements are met things all of a sudden become much more complicated. To date, generation interconnection facility(ies) as used in NERC standards are generator owner assets, "generator lead", operated at transmission voltage levels. However, if the generator lead happens to be owned by a transmission owner, then it's understood simply to be a transmission line or transmission facility. The two relay loadability standards should maintain this same simplicity and PRC-023 should apply only to TO/DP and PRC-025 to the GO. **Response:** The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, the standard is being revised to exclude the lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network from its Applicability. Also, Requirement R1, Criterion 6 is proposed for removal from the standard, as it addresses those Facilities being excluded from the Applicability. Change

Organization	Yes or No	Question 1 Comment
		made. The Generator Owner must be retained in the proposed PRC-023-3 standard to address those cases where the Generator Owner owns transmission load-responsive protective relays. Generator Owners may own transmission load-responsive protective relays applied on network transmission lines. For both standards, it is the ownership of the relays that drives the Applicability, not the ownership of the assets (e.g., GSU, transmission line). No change made. We suggest that the team take this opportunity to introduce a formally defined NERC Glossary Term for generator interconnection facility. During the recent webinar the team spent a fair amount of time indicating that when evaluating a generator interconnection facility(ies) as shown in Figure 1 and Figure 2 that it essentially comes down to the relay owner when determining which standard (PRC-023 or PRC-025) is applicable. The team indicated that if the GO owns the relay for line breaker(s) at Bus A then PRC-025 applies, but if the DP/TO owns the relay then PRC-023 applies. The team further described that the GO was left in PRC-023 to handle a situation where they may own relaying for line breaker(s) on networked transmission lines as shown in Figure 3. **Response:** The drafting team has replaced this term with "Elements that connect a GSU to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant." Change made. The team also cited they retained the GO for this situation to avoid a potential “registration tension”. The perceived need for the GO in standard PRC-023 calls into question the facility rating for the network transmission line as established under FAC-008-3. NERC standards must maintain consistent philosophies in terminology throughout all standards and cover the most common system configurations. Any unique situations will need to be dealt with on a case by case basis between asset owners. Additionally, NERC drafting teams should not be writing standards to cover

Organization	Yes or No	Question 1 Comment
		one-off configurations simply to address potential entity registration concerns. **Response:** The drafting team found that these conditions exist throughout North America in varying degrees due to industry deregulation and other factors. The drafting team is defining criteria such that similar Facilities will be subject to similar requirements regardless of Facility ownership as it relates to the NERC functional model. No change made. While FE strongly objects to the use of R7, R8 and Attachment C in PRC-023, if the team does not agree with our proposal to remove the GO completely from PRC-023 then as an alternate approach we support comments filed by Pepco Holdings, Inc. - PHI which suggesting adding the TO/DP to PRC-025 and removing R7, R8 and Attachment C from PRC-023. Either approach (FE's or PHI's) requires retaining item 6 of R1 in PRC-023. **Response:** In removing the previously proposed Requirements R7 and R8 in PRC-023-3, the standard is being revised to exclude the lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network from its Applicability. Also, Requirement R1, Criterion 6 is proposed for removal from the standard, as it addresses those Facilities being excluded from the Applicability. Change made. The Generator Owner must be retained in the proposed PRC-023-3 standard to address those cases where the Generator Owner owns transmission load-responsive protective relays. Generator Owners may own transmission load-responsive protective relays applied on network transmission lines. For both standards, it is the ownership of the relays that drives the Applicability, not the ownership of the assets (e.g., GSU, transmission line). No change made. The criterion in PRC-025-1 is technically similar, but more precise than PRC-023-2 Requirement R1, Criterion 6; therefore, Criterion 6 must be removed. The drafting team acknowledges that entities that previously implemented Criterion 6 may find that changes are necessary; if so, the PRC-025-1 Implementation Plan would apply. Change

Organization	Yes or No	Question 1 Comment
		made. In summary, for PRC-023, FE proposes the following: 1.) Remove the Generator Owner applicability 2.) Remove Requirements 7 and 8 since they will be included in PRC-025 3.) Remove Attachment C 4.) Change Requirement 1 Criteria #6 to read as follows: “Set transmission line relays applied on transmission lines connected to generation stations remote to load directional towards the generator so they do not operate at or below 115% of the rating of the generator as calculated according to applicable NERC standards.” Although not our preferred option, we also recommend the team considered the suggestion by PHI that would add the TO as an applicable entity to PRC-025 while also removing PRC-023 R7, R8 and Attachment C. **Response:** Thank you for adding the summary. Please see the above responses.
Response: The drafting team thanks you for your comments; please see the above responses.		
DTE Electric	No	Comments: The distinction is not clear between these two standards regarding generator owner relays that look toward the transmission system. Perhaps specifying the application location of the relay (CT and PT inputs) would help in clarifying the differences
Response: The drafting team thanks you for your comment and notes that load-responsive protective relays applied on "Elements that connect a GSU to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant" (which replaces the previously-used term, “generator interconnection Facility”) are covered under the proposed PRC-025-1 standard. Load-responsive protective relays applied on network transmission lines are covered under the proposed PRC-023-3 standard. Please refer to the revised Figures 1, 2, and 3 in the proposed PRC-025-1 Guidelines		

Organization	Yes or No	Question 1 Comment
and Technical Basis for further information on applications. Change made.		
Bonneville Power Administration	No	The requirements for generator interconnection facilities in PRC-023-3 apply to Transmission Owner's (and Distribution Provider's, and the requirements for generator interconnection facilities in PRC-025-1 apply to Generation Owner's. BPA believes that putting requirements for the generator interconnection facilities in two separate standards and making the applicability of the standards different is confusing and unnecessary. BPA recommends that all interconnection facilities, regardless of ownership, should be covered within one standard to provide uniformity in the application of settings for interconnection facilities.
Response: The drafting team thanks you for your comment and has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made.		
ACES Standards Collaborators	No	There is definitely much clearer delineation between what is required in PRC-023 by the Transmission Owner and Distribution Provider and in PRC-025 by the Generation Owner for generator step up transformers, generators, auxiliary transformers and generator interconnection facilities. However, PRC-023 still has other requirements that are applicable to Generators Owners that do not make sense, create compliance risks and, thus, detract from reliability by distracting the Generator Owner from value added reliability activities. For example, PRC-023 R1 is still applicable to the Generation Owner and it should not be. A Generation Owner does not own transmission beyond the generator interconnection facility. This is recognized in Project 2010-07 Generator Requirements at the Transmission Interface and NERC's work surrounding the GO/TO and GOP/TOP registration issues. If a Generator Owner owned transmission beyond the generator

Organization	Yes or No	Question 1 Comment
		interconnection facility, they would be registered as a Transmission Owner. Thus, the Generator Owner will be stuck essentially going through a registration exercise for every compliance activity to prove that the requirements do not apply because they do not own transmission facilities. Other requirements in PRC-023 that require removal of Generator Owner include R2, R3, R4, and R5. Until these removals occur, we will not be able to support the standard.
Response: The drafting team thanks you for your comment and notes that the Generator Owner must be retained in the proposed PRC-023-3 standard to address those cases where the Generator Owner owns transmission load-responsive protective relays. Generator Owners may own transmission load-responsive protective relays applied on network transmission lines. For both standards, it is the ownership of the relays that drives the Applicability, not the ownership of the assets (e.g., GSU, transmission line). No change made.		
Chelan County PUD	No	It seems that GSU and UAT would be subject to PRC-023 and PRC-025. It would be cleaner if one standard applied to GSU and UAT and the other to the transmission circuits.
Response: The drafting team thanks you for your comment and has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. With the changes, the GSU and UAT now apply to one standard, the proposed PRC-025-1.		
Western Farmers Electric Cooperative	No	See comments to question 5
Response: The drafting team thanks you for your comments; please see responses in question 5.		

Organization	Yes or No	Question 1 Comment
Ameren	No	(1) For consistency, we believe that PRC-023-3 requirement R7 should only apply at 200kV and above. Therefore, we request the SDT to change 4.2.3.1 to 'Transmission lines operated at 200kV and above that are used..."
Response: The drafting team thanks you for your comment and has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. Although PRC-023 has a provision for addressing Facilities less than 200 kV for transmission network load-responsive protective relays; however, the drafting team is addressing generation Facilities such that the PRC-025 standard will be consistent with the definition of the Bulk Electric System (BES). Including those generation Facilities that are less than 200 kV addresses all BES generation which may be important during an event where field-forcing increases the need for a reasonable level of loadability. No change made.		
American Electric Power	No	AEP believes that both documents would benefit from the inclusion of a simplified GO/TO interface diagram showing the overlap and applicability of the two standards within the opening section of each standard. Clarity needs to be provided to PRC-023-3 regarding the proper consideration of GO-owned transmission line protection systems. It must be understood that for load responsive relays subject to R7 and R8, the responsibility to perform loadability evaluations is on whoever is the owner of the Protection System. Regarding PRC-023-3, it is unclear exactly what facilities are included in the term “BES Generating Unit”. It is requested that this be clarified. AEP also requests clarification on the voltage levels applicable to Regarding PRC-023-3 R7. Section 4.2.3.1 currently applies to “transmission lines” which implies that all voltage levels would be subject to this requirement. It is requested that this be revised to clarify exactly what voltage applies.

Organization	Yes or No	Question 1 Comment
Response: The drafting team thanks you for your comment and notes that the Generator Owner must be retained in the proposed PRC-023-3 standard to address those cases where the Generator Owner owns transmission load-responsive protective relays. Generator Owners may own transmission load-responsive protective relays applied on network transmission lines. For both standards, it is the ownership of the relays that drives the Applicability, not the ownership of the assets (e.g., GSU, transmission line). No change made. The circumstance is the same as the current definition of Bulk Electric System that apply to the those individual generating units 20 MVA and larger or 75 MVA in aggregate on a site, including those Blackstart generating units identified in the Transmission Operator's system restoration plan. No change made. The drafting team notes that load-responsive protective relays applied on "Elements that connect a GSU to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant" (which replaces the previously-used term, "generator interconnection Facility") are covered under the proposed PRC-025-1 standard. Load-responsive protective relays applied on network transmission lines are covered under the proposed PRC-023-3 standard. Please refer to the revised Figures 1, 2, and 3 in the proposed PRC-025-1 Guidelines and Technical Basis for further information on applications. Change made. With the removal of Requirements R7 and R8, the Applicability section 4.2.3.1 is no longer relevant. Change made.		
Luminant Generation	No	Luminant recommends the following: (1) Load responsive relays identified in PRC-025-1 and 023-3 connected on generator breaker(s) at the GSU high side and are primarily used for backup of failed transmission line relaying shall use options in Attachment C (PRC-023-3) and Attachment 1 (PRC-025-1). (2) Load responsive relays identified in PRC-023-3 and connected on the high side of the GSU that are primarily used for transmission line protection shall use the existing criteria in PRC-023-2, Requirements R1 through R6. The above recommendations can be done by adding diagrams in PRC-023-3 and clarifying Figures 1, 2, and 3 in PRC-025-1.

Organization	Yes or No	Question 1 Comment
Response: The drafting team thanks you for your comment and notes that load-responsive protective relays applied on "Elements that connect a GSU to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant" (which replaces the previously-used term, "generator interconnection Facility") are covered under the proposed PRC-025-1 standard. Load-responsive protective relays applied on network transmission lines are covered under the proposed PRC-023-3 standard. Please refer to Figures 1, 2, and 3 in the proposed PRC-025-1 Guidelines and Technical Basis for further information on applications. No change made.		
Ingleside Cogeneration LP	No	Even though the language in both standards draws a technically accurate bright line, Ingleside Cogeneration believes that the addition of the generator relay criteria to PRC-023-3 is confusing at best. It appears that the issue has to do with the ownership of the relays. In some cases the DP and/or the TO owns a load responsive relay that is protecting generation equipment. Conversely, some GOs own load responsive relays that protect transmission equipment. If the concept of the two standards is that PRC-023-3 applies to transmission-related relays and PRC-025-1 applies to generation-related relays, than the owner of the relay is not a gating factor. This means that the applicability table for both standards would include DPs, GOs, and TOs. There would be no repeated criteria between the standards in this arrangement - and less confusing in our view.
Response: The drafting team thanks you for your comment and has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made.		
Luminant Energy Company LLC	No	See Luminant Generation Company LLC comments.
Response: The drafting team thanks you for your comments; please see the response(s) for Luminant Generation Company LLC.		

Organization	Yes or No	Question 1 Comment
Public Service Enterprise Group	No	For UATs per PRC-025-1, that are energized from the system (as opposed to from the GSU), the SDT seems to assumes that no TO or DP owns the load responsive relays for these UATs. Has that been verified by the SDT?
Response: The drafting team thanks you for your comment and notes it has not independently verified this particular scenario; however, with the proposed revisions, the Distribution Provider and Transmission Owner that own load-responsive protective relays regarding the unit auxiliary transformer (UAT) are now applicable under the proposed PRC-025-1 standard. The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made.		
Flathead Electric Cooperative	No	it is not clear to me how this would impact very small dispersed generators.
Response: The drafting thanks you for your comments. This would not have any impact on very small dispersed generators unless they form aggregated generation at a single interconnection point as delineated in the latest approved BES definition (i.e., those individual generating units 20 MVA and larger or 75 MVA in aggregate on a site). No change made.		
Kansas City Power and Light	No	We do not think that the Requirements added to the PRC-023-2 are any different than the Requirements in PRC-025-1. We agree that the addition of PRC-025-1 will cause the removal of part 6 of Requirement 1 in PRC-023-2.
Response: The drafting team thanks you for your comment and has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, the standard is being revised to exclude the lines		

Organization	Yes or No	Question 1 Comment
that are used exclusively to export energy directly from a BES generating unit or generating plant to the network from its Applicability. Also, Requirement R1, Criterion 6 is proposed for removal from the standard, as it addresses those Facilities being excluded from the Applicability. Change made.		
Liberty Electric Power LLC	No	
Dominion	Yes	Dominion agrees that the addition of requirements in PRC-023-3, R7 and R8 strengthens the bright line between the two standards. However, we do not agree with use of the term "Transmission' in 4.2.3.1 as it is our position that it does not conform with the intent of the term as defined in the NERC Glossary of Terms. We therefore suggest the sentence be revised to read "Lines that are used solely to export energy directly from a BES generating unit or generating plant to the network."
Response: The drafting team thanks you for your comment and notes that the comment above is no longer relevant because: The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made.		
Operational Compliance	Yes	Content is good. However - the two standards should refer to EXACTLY the same table of Relay Loadability Evaluation Criteria with EXACTLY the SAME OPTION #s for each Relay Type/Application. The table could stand on its own and each record be labeled with PRC-025 and/or PRC-023 applicability (new column(s)).
Response: The drafting team thanks you for your comment and notes that the comment above is no longer relevant because: The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive		

Organization	Yes or No	Question 1 Comment
protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
MRO NERC Standards Review Forum	Yes	
SERC Protection and Controls Subcommittee	Yes	
PPL NERC Registered Affiliates	Yes	
Western Area Power Administration	Yes	

Organization	Yes or No	Question 1 Comment
Duke Energy	Yes	
Tennessee Valley Authority	Yes	
PacifiCorp	Yes	
AESI Inc.	Yes	
Idaho Power Company	Yes	
Xcel Energy	Yes	
Independent Electricity System Operator	Yes	
Northeast Utilities	Yes	
Manitoba Hydro	Yes	
ReliabilityFirst	Yes	
Tacoma Power	Yes	
South Carolina Electric and Gas	Yes	
Entergy Services, Inc.	Yes	

Organization	Yes or No	Question 1 Comment
(Transmission)		
Southwest Power Pool	Yes	

2. **Does the Table 1: Relay Loadability Evaluation Criteria in both PRC-023-3 (Attachment C) and PRC-025-1 (Attachment 1) clearly identify the criteria for setting load-responsive protective relays? If not, provide specific detail that would improve the clarity of Table 1.**

Summary Consideration: In whole, the comments presented in this question were minority comments. Approximately, two comments representing 16 stakeholders reiterated that Requirements R7 and R8 should be removed from PRC-023. The drafting team removed the requirements and instead added the Distribution Provider and Transmission Owner to PRC-025 to avoid a gap or overlap in compliance as addresses in the above question.

The most notable minority comment by the SERC Protection Control Subcommittee identified key elements missing in PRC-025-1 that were addressed in PRC-023. That item was "Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications." The drafting team agreed and added these elements to the proposed PRC-025-1, Attachment 1, Table 1.

Also, one entity objected to the use of "Regional Reliability Organization (RRO)" within the two standards due to being outdated. The drafting team re-evaluated the use of the term which was added to address an implementation gap between the MOD-025-2 standard that is pending regulatory approval and the subsequent approval of PRC-025-1. The problem stemmed from the applicable entities possibly not having an official reported value to the Transmission Planner pursuant to MOD-025-1 which could pose a compliance risk. To resolve this issue, the drafting team agreed with support of comments and regulatory staff to increase the PRC-025-1 standard Implementation Plan by one year. This would ensure that MOD-025-1 would be fully in effect (about 6 months) upon the date which entities must demonstrate compliance with PRC-025-1.

One entity suggested to the drafting team to provide references within the PRC-025-1, Table to improve the clarity. Previously, the drafting team in Table 1 and in options addressing the generator-side relay of the GSU, referenced the high-side option to help direct readers to the corresponding option. The drafting team clarified the high-side options with the same reference back to the generator-side relay of the GSU. The remaining comments, all minority comments, related to technical issues the drafting team worked through in earlier postings. Items such as using the generator nameplate, seasonal variation, or items addressed more fully in other questions in this comment report.

Organization	Yes or No	Question 2 Comment
Pepco Holdings Inc. & Afffiliates	No	For the PRC-025 standard the inclusion of Table 1 along with the Figures and Example Calculations in the Guidelines and Technical Basis document clearly identifies the proposed setting criteria. However, the inclusion of Table 1 in PRC-023 overly complicates the scope of PRC-023, and without inclusion of the corresponding Guidelines and Technical Basis document makes application of Table 1 criteria difficult. We feel strongly that all references to load responsive relays applied on generators, GSU's, UAT's and Generation Interconnection Facilities (including Table 1 and Requirements R7 and R8) should be eliminated from PRC-023 as they are already adequately covered in PRC-025. Transmission Owners that own load responsive relays on those types of facilities should be included as an Applicable Entity under PRC-025. (See comments submitted for Question 1).
Response: The drafting team thanks you for your comment and has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, Attachment C and its Table 1 have been eliminated. Change made.		
FirstEnergy	No	As stated above (Question 1) FE does not support the inclusion of Attachment C in PRC-023. See question 1 for more information. From a technical standpoint, we support Table 1 of PRC-025.
Response: The drafting team thanks you for your comments; please see the above responses in question 1.		
SERC Protection and Controls Subcommittee	No	There is a discrepancy between the relay functions listed in PRC-023-3 Attachment A and those identified in PRC-023-3 Attachment C Table 1 and PRC-025-1 Attachment 1 Table 1. PRC-023-3 Attachment A includes under 1.6, "Phase overcurrent supervisory

Organization	Yes or No	Question 2 Comment
		elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications." These schemes are not accounted for in the Table 1 of either proposed standard. Given these schemes are required to meet loadability criteria on transmission lines not meeting the "generator interconnection facility" designation (i.e. networked lines), the exclusion of the schemes from generator loadability criteria creates confusion. Loadability criteria should be included for "Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications" in Table 1 of both PRC-023-3 and PRC-025-1.
Response: The drafting team thanks you for your comment and has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, Attachment C and its Table 1 have been eliminated. Change made. The drafting team thanks you for your comments and agrees with this suggestion and has modified the proposed PRC-025-1 standard in Attachment 1, Table 1, Options 15a, 15b, 16a, 16b, 18 and 19 to address this condition. Change made.		
Dominion	No	Dominion believes that the appropriate designation of "Real Power output" is the generator nameplate rating however Dominion does recognize that the addition of "gross" prior to MW is an improvement to the table wording.
Response: The drafting team thanks you for your comment and notes that it considered this same concern in past meetings and concluded that the Mega-Watt (MW) value reported to the Transmission Planner was the most practical approach for a basis in		

Organization	Yes or No	Question 2 Comment
determining the required setting(s). The Generator Owner has flexibility in using a more restrictive setting, which would be the case of using the generator name plate. In option 1, for example, the requirement is to use 100% of the reported MW and 150% of the nameplate MW to arrive at the Mvar component of the complex power. The impedance element must be set less than the calculated impedance derived from 115% of the complex power, which is using criteria (1) and (2). The standard allows the applicable entities the flexibility to account for variable changes in the reported MW value and select a setting that best suits their specific operating history or expectation. No change made. Using the reported MW value accounts for environmental conditions that impact the operation of generation units and those units which operate at a level lower than their nameplate rating. This more closely achieves a loadability setting corresponding with the expected performance of the generator during field-forcing. No change made.		
Bonneville Power Administration	No	Example: A 230kV line that is connected between a substation Terminal and a Generating station. (Comment 1) This circuit fits under 4.2.3 of PRC-023-3, so it is subject to Requirement 7. The circuit also fits under 4.2.1, so it is subject to Requirements R1 throughR5. BPA believes it should only be subject to R1 through R5 or R7, not both. **Response:** The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, the Applicability – 4.2, Circuits now provide the exclusion “except lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network.” Criterion 6 in Requirement R1 remains unused. Change made.

Organization	Yes or No	Question 2 Comment
		In removing the previously proposed Requirements R7 and R8 in PRC-023-3, Attachment C and its Table 1 have been eliminated. Change made. (Comment 2) R7 requires that the load responsive relays be set in accordance with PRC-023-3, Attachment C. BPA would like to point out that the phase distance relays at the substation terminal looking toward the generation are not covered by Attachment C and believes this creates a problem as it makes it impossible for these relays to be set in accordance with Attachment C. The same problem also exists for relays at the terminal of the generator step up (GSU) transformer looking toward the generation, recognizing that this is not a normal application. Based on these issues, BPA believes Attachment C should address all relays, not just those looking towards the Transmission system. **Response:** The drafting team added text to note that load-responsive protective relays directional toward the generator are not included. Also, the drafting team notes that the load-responsive protective relays directional toward the generator are not challenged by the loadability concerns for the stressed system conditions being addressed by the proposed PRC-025-1 standard; thus, criteria for these relays are not necessary. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Texas Reliability Entity	No	(1) Texas RE objects to the use of the term Regional Reliability Organization (RRO) in Table 1. RRO is an obsolete term that NERC had been trying to purge from the standards, and we are somewhat alarmed to see it used in a new place in the standards. While we recognize that RRO is defined in the Glossary, it is not in the functional model and, at least in our region, it does not identify any entity and it is ambiguous. We urge you to replace the term RRO with an entity type from the functional model, or to write a description of what is intended without using the term

Organization	Yes or No	Question 2 Comment
		"RRO". **Response:** The reference to "…or other entity as specified by the Regional Reliability Organization (RRO)" has been removed from the standard. Change made. (2) Regarding the "Transformers" section on page 7 and footnote 3 on page 10, consider whether it is appropriate to use the "nameplate impedance at the nominal GSU turns ratio" in all instances. In some cases, it is more appropriate to use the calculated (i.e. with compensation) impedance that reflects the lowest value based on the de-energized tap and LTC tap positions for this purpose. **Response:** The drafting team notes that the tap impedance for older transformers may not be available for all tap positions; therefore, the drafting team is requiring the use of the nominal impedance. If entities wish to employ the actual tap impedance used or the most conservative tap impedance available, they may reflect that in the relay settings selected provided that the setting achieves the relay pick up setting criteria in Table 1. No change made. (3) For Options 1a, 2a, and 7a, consider using 0.9 per unit instead of 0.95 per unit, because typical disturbance (post-contingency) voltage criterion is 0.9 p.u. **Response:** The 0.95 per unit voltage specified in these options reflect the approximate generator bus voltage at a 0.85 per unit system voltage with a representative transformer impedance of 12 percent during field-forcing. No change made. (4) Consider clarifying that the Real Power output criteria should be based on the [highest seasonal] MW rating for the applicable unit. There can be significant seasonal variations in MW capabilities for some units. We don't expect pickup settings to be changed from season to season, so an appropriate year-round setting should be determined and applied. **Response:** Seasonal variations are discussed in Attachment 1: Relay Settings under the heading "Generators." The section states: "If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard." No

Organization	Yes or No	Question 2 Comment
		change made. (5) Some transmission systems have steady state stability limits that encroach into the generator capability limits. Consider adding exclusion criteria for these types of scenarios. **Response:** The drafting team notes that the generator is providing VARs to the system during field-forcing anticipated by the standard. The steady-state stability limit encroachment occurs only in the leading VAR scenario. This issue is being addressed by the NERC Board of Trustees adopted PRC-019-1 standard. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
AESI Inc.	No	The team is commended for an extensive effort to provide high level of detail through numerous relay setting examples summarized in Table 1 and elaborated in the document PRC_025_1_Guidlines_and_Technical_Basis_Draft_3_2013_04_24_Redline.pdf. Nonetheless, the following points may need further attention: 1. The settings derived by simulations versus the settings derived by manual calculations are noticeably different, the latter being repeatedly much more conservative (e.g. 8c: 6.6 A pu versus 8a: 9.5 A pu), exposing generators to a higher risk of overloading. It would be expected that the results of manual calculations and simulations would yield closer values, at least for most of typical configurations. It appears that underlying assumptions used in the calculations and simulations may need to be fine-tuned. For example, is it realistic to have field forcing producing 1.5 pu MVAR output and at the same time generator bus voltage at 0.95 pu. **Response:** The drafting team notes that "manual" calculations, in some cases, may be significantly more conservative than simulation results. However, the criteria specified by Options 1a, etc. reflect behavior observed for some generators in actual events and simulations. Therefore, the specified criteria are appropriate for non-simulation based

Organization	Yes or No	Question 2 Comment
		analysis. No change made. 2. The settings derived by manual calculations are such the generators are exposed to a higher risk of overloading: • Example 1a - 21 protection would operate only when unit loading exceeds approx. 280% (at rated power factor). • Example 2a - 51V protection pickup is set at equivalent of approx. 170% loading. Taking into account that overcurrent relays actually react when current exceeds 1.5 pickup setting, equivalent loading on the unit would have to exceed 250% before timing is initiated. Depending on the relay characteristic, time delay can be significant. **Response:** The drafting team acknowledges that fault protective relaying may not provide adequate thermal overload protection; an exclusion is provided in the proposed PRC-025-1 standard for protection that is focused exclusively on overload protection. No change made. 3. C37.102 states that acceptable settings for 21 function are 150% to 200% (at rated power factor). These values should guide the requirements of this standard. **Response:** The drafting team notes that for some generators a setting of 150% to 200% of the generator MVA rating at its rated power factor is insufficient and is moving beyond the general application guidance expressed in C37.102 so that load-responsive protective relays allow generators to support the system during stressed conditions to the extent possible. The drafting team also notes that while C37.102 provides general guidance on the reach for phase fault backup protection, it also provides insight regarding situations in which voltage regulator action could cause an incorrect trip. Similar to information in the Guidelines and Technical Basis for PRC-025-1, C37.102 notes that consideration should be given to reducing the reach of the relay and/or coordinating the tripping time delay with the time delays of the protective

Organization	Yes or No	Question 2 Comment
		devices in the voltage regulator. It also recommends that the setting of these relays be evaluated between the generator protection engineers and the system protection engineers to optimize coordination while still protecting the turbine generator, and that stability studies may be needed to help determine a set point to optimize protection and coordination. No change made. 4. The Table specifies pickup setting criteria. It remains unclear when are the relays allowed to trip. **Response:** The drafting team notes that the impedance elements are allowed to trip at less than the pickup setting criteria and overcurrent elements are allowed to trip at greater than the pickup setting criteria. Timing considerations such as relay coordination are not addressed by this standard. No change made. 5. Examples 7a, b, c, seem to be duplication of 1a, b, c. **Response:** Refer to Figure 4 in the Guidelines and Technical Basis. Option 1 relays are located on the generator and Option 7 relays are on the low-side terminals of the generator step-up (GSU) transformer. No change made. 6. The following comment from the Guidelines document is not clear:======Options 7a and 10, Table 1 - Bus Voltage, calls for a 1.0 per unit of the high-side nominal voltage for generator busvoltage, ***however due to the presence synchronous generator 0.95 per unit bus voltage will be used as (Vgen)***?:========== **Response:** The description prior to Equation 76 in the Guidelines and Technical Basis has been clarified as to why the 0.95 voltage is being used in the case of mixed synchronous and asynchronous generation. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Xcel Energy	No	For 51 relay that is installed on the high side of GSU, we suggest it should be an acceptable option if the 51 relay setting meets R1 Criteria 11.

Organization	Yes or No	Question 2 Comment
Response: The drafting team thanks you for your comments notes that the criteria expressed in PRC-023-3, R1 Criterion 11, represents steady-state conditions for transmission transformers and does not represent the conditions that the GSU would see during field-forcing conditions. No change made.		
Ameren	No	(1) We ask the SDT to clarify that 'nameplate MVA rating' means the 'generator nameplate MVA rating'. Therefore we request that the SDT either add a statement "Unless otherwise stated, 'nameplate MVA rating' means the 'generator nameplate MVA rating' throughout Table 1", or insert 'generator' before 'nameplate MVA rating'.
Response: The drafting team thanks you for your comments and has added “generator” immediately prior to the applicable uses of “nameplate MVA rating” in Table 1. Change made.		
American Electric Power	No	PRC-023-3 must be clear in stating that, if a Transmission or Distribution line used solely to export energy directly from the GU has its own circuit breaker, then the existing R1 through R5 criteria should be applied based on the rating of the line. **Response:** The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, the Applicability – 4.2, Circuits now provide the exclusion “except lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network.” Criterion 6 in Requirement R1 remains unused. Change made. PRC-023-3 appears to exclude relays directional toward the Generating Unit. For example, if you attempt to evaluate loadability for two-terminal 345kV line to a

Organization	Yes or No	Question 2 Comment
		windfarm, it appears to be applicable to both PRC-023-3 4.2.1 and 4.2.3. This would make it difficult to determine what Transmission lines are subject to evaluation and which requirement to apply, R1 or R7. Based on the current draft, it is not clear what criteria set to apply. The criteria in Table 1 is based on Generator's power while the criteria in Requirement 1 is based on circuit ratings. It needs to be clarified which criteria set is to be applied. A second example is in a situation when a loadability evaluation is needed for a two-terminal line that is definitely not applicable to 4.2.1., but *is* applicable to 4.2.3. The intent of having two standards appears to be to have the relays on the Generating Unit end owned by the GO, set according to criteria R1 in PRC-025-1; and to have the relays on Generating Unit end owned by the TO, set according to criteria R7 in PRC-023-3. In this example, there would appear to be no criteria required to set relays on the end external to the Generating Unit, for relays owned by either the GO or TO. Clarification is needed to define responsibility based on Protection System ownership as well as to clearly convey the applicability of remote protection systems. **Response:** The drafting team added text to note that load-responsive protective relays directional toward the generator are not included. Also, the drafting team notes that the load-responsive protective relays directional toward the generator are not challenged by the loadability concerns for the stressed system conditions being addressed by the proposed PRC-025-1 standard; thus, criteria for these relays are not necessary. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Luminant Generation	No	Luminant disagrees that the criterion for setting load responsive relays is clear because of the bright line is vague. Luminant recommends that each standard be clear in addressing the relay setting criteria by its primary application.
Response: The drafting team thanks you for your comment and notes that load-responsive protective relays applied on		

Organization	Yes or No	Question 2 Comment
"Elements that connect a GSU to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant" (which replaces the previously-used term, "generator interconnection Facility") are covered under the proposed PRC-025-1 standard. Load-responsive protective relays applied on network transmission lines are covered under the proposed PRC-023-3 standard. Please refer to the revised Figures 1, 2, and 3 in the proposed PRC-025-1 Guidelines and Technical Basis for further information on applications. Change made.		
Luminant Energy Company LLC	No	See Luminant Generation Company LLC comments.
Response: The drafting team thanks you for your comments; please see the response(s) for Luminant Generation Company LLC.		
Kansas City Power and Light	No	We do not think that the information that is shown in the Attachment is very easy to understand but the additional information in the Guidelines and Technical Basis section helps to understand what the table is requesting. Please add to the table the examples shown in the Guidelines and Technical Basis or at a minimum refer to the location the example can be found in that document. This will assist in the understanding of the table. **Response:** The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, Attachment C and its Table 1 have been eliminated. Change made. In the Guidelines and Technical Basis the calculation the previous value used for MW was based on the PF for Max Generation. In the new example the value of MW used

Organization	Yes or No	Question 2 Comment
		changed why did that value change? **Response:** In the previous draft of the calculations, the $P_{reported}$ and the calculated P happened to be the same value and caused confusion. Because of the identical values, the drafting team decided to use a different value for $P_{reported}$ so that the values would not be confused. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Western Area Power Administration	Yes	Recommend adding reference to Table 1 - Options 7, 8, 9, 10, 11, 12 - Relay Type back to options 1, 2, 3, 4, 5, 6 for applications on the generator side of the GSU. The language and reference used in the Relay Type column for Options 1-6 added clarity and should be mirrored in Options 7-12.
Response: The drafting team thanks you for your comment and agrees that where the generator-side options refer to the high-side options, that the high-side options should also refer to the generator-side options. Change made.		
ACES Standards Collaborators	Yes	The table is much clearer than in past versions. However, we do recommend one minor additional change. The option numbers should be reset to 1 for every application and relay type combination since they are truly options within those combinations. Otherwise, a reader may be believe they have 19 options and only have to pick one relay type and application to apply.
Response: The drafting team thanks you for your comment and suggestion; however, the drafting team asserts the use of sequential numbering is more beneficial and avoids confusion when referring to an option. No change made.		
Operational Compliance	Yes	But...see comments for Question #1.
Response: The drafting team thanks you for your comments; please see the above responses for question 1.		

Organization	Yes or No	Question 2 Comment
Manitoba Hydro	Yes	(1) Manitoba Hydro suggests eliminating Table 1 from one of the standards and referencing it in the other standard, since both PRC-023-3 and PRC-025-1 are already very lengthy standards.
Response: The drafting team thanks you for your comment and has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, Attachment C and its Table 1 have been eliminated. Change made.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
MRO NERC Standards Review Forum	Yes	
PPL NERC Registered	Yes	

Organization	Yes or No	Question 2 Comment
Affiliates		
Duke Energy	Yes	
Tennessee Valley Authority	Yes	
PacifiCorp	Yes	
Chelan County PUD	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Northeast Utilities	Yes	
ReliabilityFirst	Yes	
Tacoma Power	Yes	
South Carolina Electric and Gas	Yes	
Ingleside Cogeneration LP	Yes	
Entergy Services, Inc. (Transmission)	Yes	

Organization	Yes or No	Question 2 Comment
Southwest Power Pool	Yes	

3. **Does PRC-025-1, Guidelines and Technical Basis provide a clear understanding of the various criteria, including the options (e.g., 1a, 1b, 1c, 2a, etc.) for setting load-responsive protective relays? If not, provide specific detail that would improve the Guidelines and Technical Basis.**

Summary Consideration: There were three significant comments in this question. One comment representing about five stakeholders suggested defining "generator interconnection Facility." The drafting team addressed this in several comments and the summary can be found in the summary to question 1. Second, the same comment revealed minor errors in a Figure, calculation, and within the Guidelines and Technical Basis. The drafting team corrected these errors and made clarifications. Also, this commenter suggested performing calculations in per unit; however, the team disagreed that the current method was adequate.

Other minority single comments relate to issues the drafting team has worked through in earlier postings of the standard. They include the basis why transformers are being addressed, applicability of the UAT used only during startup, multi-winding example calculation, changes in the reported Real Power out to the Transmission Planner (e.g. seasonal variations), appending the Guidelines and Technical Basis back to the standard, and request for clarity in the examples.

Organization	Yes or No	Question 3 Comment
Pepco Holdings Inc. & Afffiliates	No	1) The new term "Generator Interconnection Facilities" is not defined in the NERC Glossary of terms, nor is it defined in the body of the standard. It is defined in the Guidelines and Technical Basis document; however, we feel this term needs to be defined within the body of the standard itself. Perhaps a footnote similar to that used to define Unit Auxiliary Transformers would be appropriate. We would suggest the same definition used in the Guidelines and Technical Basis document be inserted: "Generator interconnection Facility(ies) consists of Elements between the generator step-up transformer and the interface with the portion of the bulk Electric System (BES) where Transmission Owners take over the ownership." **Response:** The drafting team has replaced this term with "Elements that connect a GSU to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant." Change made.

Organization	Yes or No	Question 3 Comment
		2) In Figures 4 and 5 the CT's supplying the 21, 51V-R and 51V-C relays connected to the generator(s) look like they are connected to the generator neutral. To make it clear that they are supplied from CT's connected in the phase leads, a phase to neutral transition symbol (ref Fig 7.4 in IEEE C37.102) should be used to indicate the CTs are located above the neutral connection point. **Response:** Figures 4 and 5 have been modified to address this concern. Change made. 3) In Figure 5 there is a 51 relay shown connected to the 22kV bus leads supplying the generator on the left hand side of the drawing. This 51 relay is not reverenced, or used, in any of the options and therefore should be removed from the drawing. **Response:** Figure 5 and Table 1, Option 5 has been revised to address this concern. Change made. 4) Options 14a, 14b, 15a, 15b, 16a and 16b all use an MVAR value equal to 120% of the aggregate generation MW value, instead of the 150% value used when the relays are located on the generator side of the GSU transformer. Presumably this is to account for the I squared Xt MVAR loss consumed in the GSU transformer. However, there is no mention of this fact in the Guidelines and Technical Basis document. To avoid confusion as to why different MVAR criteria are used, supporting technical justification / explanation should be offered in the document. **Response:** The assumption is correct. Discussion has been added to the Guidelines and Technical Basis. Change made. 5) The example calculations for Options 4 and 10 are combined as a single identical set of calculations. This calculation is appropriate for Option 10 but not for Option 4. Referring to Figure 5, the 21 relays for Option 4 are shown connected to each individual generator. Also the 20MVAR static compensation source is connected upstream of each generator relay. As such, the 21 relay on each individual generator (Option 4) will only see the MW and MVAR flows from a single generator, not the aggregate of all the generation plus the 20MAR reactive source. A separate

Organization	Yes or No	Question 3 Comment
		calculation for Option 4 should be developed. For that Option 4 case the single generator apparent power (assuming three generators of equal size) would be 102/3 = 34 MW and 63.2/3 = 21 MVAR, which is 40 MVA for each generator. **Response:** Figure 5 in the Guidelines and Technical Basis has been modified to account for this discrepancy and the calculation example for Option 4 and 10 have been separated. Change made. 6) The example calculations for Option 5 appear to be incorrect. Again referring to Figure 5, the 51V-R relays for Option 5 are shown connected to each individual generator. Also the 20MVAR static compensation source is connected upstream of each generator relay. As such, the 51V-R relay on each individual generator (Option 5) will only see the MW and MVAR flows from a single generator, not the aggregate of all the generation plus the 20MAR reactive source. As such the 51V-R relay should be set to 130% of the maximum MVA rating of that individual generator. Again assuming three units of equal size, each generator would be rated 40MVA and therefore the 51V-R relay should be set to not operate below 1.3 x 40 = 52 MVA **Response:** The calculation for Option 5 in the Guidelines and Technical Basis has been corrected to reflect a single asynchronous generation unit and not the aggregate. Change made. 7) The example calculations for Options 7a, 10, 8a, 9a, 11, and 12 illustrate a mixture of synchronous and asynchronous generators. However, there is no corresponding one-line drawing which corresponds to these examples. Because of this, it is difficult visualize the topology of this arrangement and where the corresponding relays would be located. If the SDT wishes to provide an example calculation where there is a mix of synchronous and asynchronous generation then we would suggest an additional figure be added (Figure 6) which would illustrate this type of connection. **Response:** Figure 5 and the calculations for Option 10 in the Guidelines and Technical Basis has been modified and corrected to reflect a mixture of synchronous and

Organization	Yes or No	Question 3 Comment
		asynchronous generators (Equations 71-93). Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
PPL NERC Registered Affiliates	No	See Comments for Question #5
Response: The drafting team thanks you for your comments; please see the responses for question 5.		
North American Generator Forum Standards Review Team	No	See comments to question 5 below
Response: The drafting team thanks you for your comments; please see the responses for question 5.		
Duke Energy	No	Examples of calculations are helpful. However, more details on the root of the calculations are needed. Exclusively calculating values on a per unit basis would add more clarity.
Response: The drafting team thanks you for your comment and asserts the basis for the calculations are addressed in the Guidelines and Technical Basis narrative. The drafting team also notes that Generator Owners may perform calculations in per unit or in actual values. The examples are provided in actual values. No change made.		
JEA	No	While it has been demonstrated in the 2003 blackout that a small percentage of generating units did trip off line prematurely due to conservative setting of generator protection systems, no evidence has been provided that transformer tripping contributed to the cause of the generation outages. The sole purpose as stated by the SDT for including transformers is a directive from FERC. We believe that there should be some evidence as to the benefit of preforming protection modifications to

Organization	Yes or No	Question 3 Comment
		transformers and that they should not simply be included until a study can be performed to show the cost benefit analysis and therefore recommend that transformers be excluded during this phase and be incorporated into a phase III. **Response:** FERC has already ruled on entities' requests for clarification and rehearing on Order 733 with regard to this matter. The drafting team notes that entities may change the configuration or operation of their network to facilitate compliance but not to eliminate a compliance obligation. No change made. If transformers are to be included, an exception should be provided to allow the start-up transformer to be used to provide auxiliary power in case of failure of the auxiliary transformer. BES reliability is better served by allowing this exception (which will occur very infrequently) than to keep the generating unit off line for fear of being out of compliance with a standard. **Response:** The drafting team contends that if this is an anticipated operating condition, the protective relays on the alternate source of station service would need to be compliant with the standard. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Bonneville Power Administration	No	While the Guidelines and Technical Basis provides useful information, BPA is concerned that this document will not be approved by FERC as part of the standard and thus the standard must be capable of standing on its own. For this reason, BPA requests that clarification provided in the Guidelines and Technical Basis document be included into the standard specifically in regards to 'generator interconnection facilities'.
Response: The drafting team thanks you for your comments and will re-append the Guidelines and Technical Basis document to the standard prior to filing with FERC. The documents were separated for management purposes and to facilitate editing between team members. No change made.		

Organization	Yes or No	Question 3 Comment
AESI Inc.	No	Please see comments on Question 2.
Response: The drafting team thanks you for your comments; please see the above responses in question 2.		
Western Farmers Electric Cooperative	No	See comments to question 5
Response: The drafting team thanks you for your comments; please see the responses below in question 5.		
Xcel Energy	No	In the last paragraph on page 19 of the clean version of the PRC-025-1 Guidelines and Technical Basis, the following sentence appears: "Phase time overcurrent relays applied to the UAT that act to trip the generator directly or via lockout or auxiliary tripping relay are to be compliant with the relay setting criteria in this standard." This typically would be the case for UAT's connected to the generator bus. However, for system connected auxiliary transformers as shown in Fig 6 on page 20, it is very unlikely that the time overcurrent relays protecting the system connected transformers will act to trip the generator directly or via lockout as this is a different zone of protection and to do so might result in an unnecessary challenge of the unit's overspeed protection. Instead, these overcurrent relays will trip the source breakers feeding the system connected auxiliary transformer but will not act to directly trip the generator. The generator will ultimately trip because of the resultant loss of power to the auxiliary system when the source breakers feeding the auxiliary transformer are tripped. The loss of auxiliary power will likely result in some form of a turbine/prime move trip and the generator breaker will be tripped open once power output drops to zero. In this manner, unit overspeed protection is not unnecessarily challenged. It seems that the quoted sentence on page 19 only serves to confuse the matter. If the goal of this setting requirement is to not to have the plant trip due to a loss of auxiliary power based on overly conservative setting of overcurrent relays, it is immaterial

Organization	Yes or No	Question 3 Comment
		whether the overcurrent relays act to trip the generator directly or via lockout or auxiliary tripping relay or if the plant ultimately trips because a loss of auxiliary power caused by overcurrent relays opening source breakers to the system connected auxiliary transformer. We recommend the quoted sentence be stricken from the guideline and technical basis document.
Response: The drafting team thanks you for your comments and contends that the load-responsive protection for any UAT that supplies "running station power" to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made.		
ReliabilityFirst	No	1) There appears to be an error in the Guidelines and Technical Basis document on page 23 for option 15b. It indicates that the Reactive Power output that equates 120% of the maximum gross Mvar output whereas Table 1 states 100%. **Response:** Yes, this was an error in the Guidelines and Technical Basis document for Option 15b. The value should be 100% of the output determined by simulation like the other options. Change made. 2) A statement should be inserted that the iterative calculation stopped because the change was < 1%. This applies to options 1b & 7b on page 31 and option 2b on page 38. Also, if an entity knows the resistive and reactive impedances of the transformer, the entity could directly calculate the low-side GSU voltage from the high-side voltage, the per unit current through the GSU and the full impedance of the transformer. **Response:** This convergence of the equation is addressed for Options 1b and 7b in the calculations above Equation 14. This text was not provided in the calculation for Option 2b; therefore, it will be added to improve overall clarity. There are two variables in this calculation which depend on each other; therefore iteration is necessary. Change made.

Organization	Yes or No	Question 3 Comment
Response: The drafting team thanks you for your comments; please see the above responses.		
Ameren	No	(1) We request the SDT to add a multiple winding transformer example. We recommend that the SDT include an example with equally rated CTGs connected to equally rated dual secondary transformer windings stepping up to a single high voltage winding, because it is commonly used. **Response:** For the configuration above, the GSU relays will be set on an aggregated generator basis. The generator relay setting will be set on an individual generator basis. The drafting team contends that the calculations provide adequate direction for this configuration. No change made. (2) The MW capability reported to the Transmission Planner changes by a very small amount from time to time. As written we believe that this could trigger a significant amount of documentation. We request the SDT to show in your example (s) how an increased margin would address such a small change (e.g. a 2% increase from the originally documented value) before triggering such a review. **Response:** The drafting team contends that if an entity is concerned about minor changes in the reported capability, the entity can reflect these minor changes as increased margin in their relay setting. No change made. (3) On page 2 of the Guidelines and Technical Basis document, we ask the SDT to delete 'Generator Owner' from the last sentence of Figure 2 caption. **Response:** This was recognized as an error after the posting. The "Generator Owner" has been removed from the Figure 2 text. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Luminant Generation	No	Figures 1, 2, and 3 do not provide a sufficient bright line between the application of PRC-025-1 and PRC-023-3 for setting criterion. Luminant recommends that additional

Organization	Yes or No	Question 3 Comment
		information be added that identifies that a load responsive relays located on the transmission line breaker at Bus A and are primarily installed for transmission line protection use PRC-023-3 criterion Requirements R1 through R6 (regardless of the number of generators or transmission lines connected to Bus A). Load responsive relays located on the high side of the GSU and are primarily used for failed transmission line protection should use PRC-023-3 (Attachment C) or PRC-025 (Table 1).
Response: The drafting team thanks you for your comment and notes that load-responsive protective relays applied on "Elements that connect a GSU to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant" (which replaces the previously-used term, “generator interconnection Facility”) are covered under the proposed PRC-025-1 standard. Load-responsive protective relays applied on network transmission lines are covered under the proposed PRC-023-3 standard. Please refer to the revised Figures 1, 2, and 3 in the proposed PRC-025-1 Guidelines and Technical Basis for further information on applications. Change made.		
Tri-State G&T	No	The generator overload protection exception added to Draft 3 for extremely inverse characteristics is a major improvement, but the term “full-load current” needs clarification. Is this the current at normal full-load turbine output and typical PF, or the value determined from the generator nameplate MVA at rated voltage, or the base (no fans, no oil circulation) rating of the GSU?
Response: The drafting team thanks you for your comments and notes that the phrase full load current refers to rated armature current of the generator. No change made.		
Luminant Energy Company LLC	No	See Luminant Generation Company LLC comments.
Response: The drafting team thanks you for your comments; please see the response(s) for Luminant Generation Company LLC.		
Entergy Services, Inc.	No	The Guidelines are still not clear about what to do with start-up transformers when

Organization	Yes or No	Question 3 Comment
(Transmission)		used in lieu of the UATs (Unit Auxiliary Transformer).
Response: The drafting team thanks you for your comments and contends that if this is an anticipated operating condition, the protective relays on the alternate source of station service would need to be compliant with the standard. No change made.		
Tennessee Valley Authority	No	
Operational Compliance	Yes	See comments for Question #1. In addition, Figures 1,2 and 3 could be clarified by 1) labelling the Generator Interconnection Facility with a pointer and parentheses, 2) include table with columns for Relay Owners, Function of Owner and Applicable Standard. This way, a quick glance at the figure can clarify which standard is applicable (rather than having to decipher the caption).
Response: The drafting team thanks you for your comment and notes that load-responsive protective relays applied on "Elements that connect a GSU to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant" (which replaces the previously-used term, "generator interconnection Facility") are covered under the proposed PRC-025-1 standard. Load-responsive protective relays applied on network transmission lines are covered under the proposed PRC-023-3 standard. Please refer to the revised Figures 1, 2, and 3 in the proposed PRC-025-1 Guidelines and Technical Basis for further information on applications. Change made.		
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company;	Yes	

Organization	Yes or No	Question 3 Comment
Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		
FirstEnergy	Yes	
MRO NERC Standards Review Forum	Yes	
SERC Protection and Controls Subcommittee	Yes	
Dominion	Yes	
PacifiCorp	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Northeast Utilities	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 3 Comment
American Electric Power	Yes	
Tacoma Power	Yes	
South Carolina Electric and Gas	Yes	
Ingleside Cogeneration LP	Yes	
Southwest Power Pool	Yes	
Kansas City Power and Light	Yes	

4. The drafting team developed an Implementation Plan for the added requirements of the proposed PRC-023-3 that aligns with that proposed in PRC-025-1. Do you agree with the proposed Implementation Plan for PRC-023-3 Requirements R7 and R8 and the proposed PRC-025-1: a. 48-months to apply load-responsive protective relay settings , where relay replacement is not required, and b. 72-months to apply load-responsive protective relay settings, where relay replacement is required? If not, provide an alternative implementation plan with specific rationale for such an alternative period.

Summary Consideration: Only a minority of commenters provided comments regarding the Implementation Plan. In past postings, a number of commenters suggested increasing the Implementation Plan due to varying factors. The drafting team was reluctant to increase the period beyond the 48 months for applying settings on relays that do not requirement replacement and 72 months for those relays which require replacement or removal. Four comments supported by 11 entities propose lengthening the period in these comments. However, based on other factors identified in question 2, the drafting team has lengthened the Implementation Plan from 48 to 60 months for applying settings on relays that do not requirement replacement and from 72 to 84 months for those relays which require replacement or removal.

One comment noted a lack of clarity on the implementation of PRC-023-3. The drafting resolved that by removing the proposed Requirements R7 and R8 and adding the Distribution Provider and Transmission Owner to PRC-023-3. One comment suggested adding the word “removed” in the “replacement” timeframe for clarity. The drafting team agreed and made the change. Another comment disagreed with the 100 percent compliance approach. The drafting team did not have any flexibility to investigate other compliance approaches. One comment suggested a phased approach to the Implementation Plan; however, the drafting team agreed the current two-phased approach is the most practical. Last, one comment suggested adding formatting to the effective date language to draw attention to “do require replacement” and “do not requirement replacement.” The drafting team did not agree the suggestion provided a substantive improvement to clarity.

Organization	Yes or No	Question 4 Comment
Duke Energy	No	Duke Energy schedules some of its generating units on a 24 month cycle for minor outages and a 96 month cycle for major outages. This would make the current

Organization	Yes or No	Question 4 Comment
		Implementation Plan very expensive and difficult to comply with if relay replacements are required. [Duke Energy suggests a 48 month and 96 month Implementation Plan. This would allow for the industry to use existing outage schedules, keeping overall costs at a minimum.]
Response: The drafting team thanks you for your comment and has increased the implementation period from 48 months to 60 months for applying settings on load-responsive protective relays that do not require replacement or removal, and from 72 months to 84 months for applying settings on load-responsive protective relays that do require replacement or removal to prevent an implementation gap with the MOD-25-2 standard which is pending regulatory approval. Change made.		
JEA	No	Considering that applying new settings and testing will require a major outage, we believe that 48 months is not a sufficient time frame for full implementation when existing equipment can be used and relay replacement is not required. We recommend 72 months be allowed even in the case where existing equipment can be used. It may take a year or more to perform the calculations and evaluated equipment and then another 5 years for a major planned outage to occur.
Response: The drafting team thanks you for your comment and has increased the implementation period from 48 months to 60 months for applying settings on load-responsive protective relays that do not require replacement or removal, and from 72 months to 84 months for applying settings on load-responsive protective relays that do require replacement or removal to prevent an implementation gap with the MOD-25-2 standard which is pending regulatory approval. Change made.		
DTE Electric	No	Comments: Suggest that allowing 72 months to become 100% compliant for both 4a and 4b would better align with the unmonitored protective relay maximum maintenance interval of 6 years specified in PRC-005-2. In this way, relay setting changes or replacements could be accommodated during normal scheduled relay maintenance. Also, 48 months could be difficult to achieve for a company with a large generation fleet.
Response: The drafting team thanks you for your comment and has increased the implementation period from 48 months to 60		

Organization	Yes or No	Question 4 Comment
months for applying settings on load-responsive protective relays that do not require replacement or removal, and from 72 months to 84 months for applying settings on load-responsive protective relays that do require replacement or removal to prevent an implementation gap with the MOD-25-2 standard which is pending regulatory approval. Change made. Also, it is beyond the drafting team's control to ensure that a standard is approved and implemented in such a way to facilitate alignment with the implementation of other standards. No change made.		
American Electric Power	No	Regarding PRC-025-1: While AEP appreciates the factors considered by the drafting team when developing the proposed implementation plan for PRC-025-1, the plan as proposed will not afford adequate time for large Generator Owners to comply with the standards. AEP has 119 generating units and 2 wind farms that are applicable to PRC-025-1. The resources needed to evaluate the generating units for compliance with PRC-025-1 and PRC-023-3 will also be engaged in implementing the new NERC standards PRC-019-1 and PRC-024-1. For these reasons, AEP believes a phased implementation plan for PRC-025-1 is more appropriate. Such a plan would require entities to show that a minimum percentage of their applicable relays are compliant within a specified time frame. For example: * Entities shall demonstrate that 30% of their applicable load-responsive protective relays are fully compliant with R1 within 48 months of the effective date of this standard. * Entities shall demonstrate that 60% of their applicable load-responsive protective relays are fully compliant with R1 within 60 months of the effective date of this standard. * Entities shall demonstrate that 100% of their applicable load-responsive protective relays are fully compliant with R1 within 72 months of the effective date of this standard. Regarding PRC-023-3: The proposed revision could significantly impact Transmission

Organization	Yes or No	Question 4 Comment
		Owners. Additional research is being conducted within AEP Transmission to determine the extent of that impact. It is possible that the proposed implementation plan would not provide adequate time to achieve compliance with the standard if it is determined to impact a high volume of facilities. Additional research will be needed before a recommendation be made on the extent the additional time required. **Response:** The drafting team has decided to integrate Transmission Owner and Distribution Provider into PRC-025-1, rather than adding Requirement R7 and R8 to PRC-023-2. All implementation will be addressed within the Implementation Plan for PRC-025-1. The drafting team thanks you for your comment and has increased the implementation period from 48 months to 60 months for applying settings on load-responsive protective relays that do not require replacement or removal, and from 72 months to 84 months for applying settings on load-responsive protective relays that do require replacement or removal to prevent an implementation gap with the MOD-25-2 standard which is pending regulatory approval. Change made. The suggested phased-in approach would be potentially unfair to small entities requiring them to become 100% compliant earlier. No change made. It is still unclear when TOs, GOs and DPs will be required to complete loadability evaluations for any circuits below 200kV included by the Planning Coordinator per Attachment B. It is understood that we will have 39 months to apply the initial list. There is confusion however on whether or not the 39 months applies to new inclusions to the list. AEP requests that this time frame be clarified and included in the standard, as it is information needed to maintain compliance on an ongoing basis. **Response:** The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities

Organization	Yes or No	Question 4 Comment
		will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. All implementation will be addressed within the Implementation Plan for PRC-025-1, and no changes are being made to the existing approved PRC-023-2 Implementation Plan.
Response: The drafting team thanks you for your comments; please see the above responses.		
Luminant Generation	No	Luminant recommends that the phrase "where relay replacement is not required" and "where relay replacement is required" add the word removal; i.e., "replacement or removal".
Response: The drafting team thanks you for your comments and the drafting team has revised items #7 and #8 in the General Considerations of the PRC-025-1 Implementation Plan as you suggest. Change made.		
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP does not agree with the 100% compliance approach that the drafting team has taken in regard to PRC-025-1. Although FERC Order 733 is cited multiple times as the reliability need, there are real dollars that the industry will need to expend to analyze and replace load responsive relays for generators of any size. We do not read Order 733 the same way - and FERC has accepted exceptions for low-impact facilities in the past.
Response: The drafting team contends that the requirements proposed within PRC-025-1 satisfy the associated FERC directive and are appropriate and necessary. Appendix 4B, Section 2 of the NERC Rules of Procedures identify and discuss the basic principles underpinning why and how NERC and the Regional Entities will determine Penalties, sanctions, and Remedial action Directives for violations of the Requirements of the Reliability Standards. By being classified as BES, the facilities involved have been determined to have impact on the reliability of the BES. No change made.		
Luminant Energy	No	See Luminant Generation Company LLC comments.

Organization	Yes or No	Question 4 Comment
Company LLC		
Response: The drafting team thanks you for your comments; please see the response(s) for Luminant Generation Company LLC.		
ACES Standards Collaborators	Yes	We agree with the 48-month and 72-month implementation plan for PRC-025 and R7 and R8 in PRC-023. However, we believe the implementation plan for PRC-023 as a whole is confusing. Since PRC-023-2 has a staggered implementation plan that is still has not fully been implemented, we recommend laying out a graphical timeline or a Gantt chart that compares PRC-023-2 implementation to that of PRC-023-3.
Response: The drafting team thanks you for your comment and has increased the implementation period from 48 months to 60 months for applying settings on load-responsive protective relays that do not require replacement or removal, and from 72 months to 84 months for applying settings on load-responsive protective relays that do require replacement or removal to prevent an implementation gap with the MOD-25-2 standard which is pending regulatory approval. Change made. The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, the Implementation Plan has been revised to note the specific milestones that are known to improve clarity. Change made. The drafting team is unable to provide a graphical timeline comparison between the standards illustrating their implementation because each is subject to NERC Board of Trustees adoption and subsequent regulatory approvals. No change made.		
Operational Compliance	Yes	Editorial note: To aid with distinguishing between options: underline the words “is necessary” and “is not necessary” for “Implementation Date” columns.
Response: The drafting team thanks you for your comments and contends that it is not necessary to add the emphasis suggested.		

Organization	Yes or No	Question 4 Comment
No change made.		
Pepco Holdings Inc. & Afffiliates	Yes	
FirstEnergy	Yes	
MRO NERC Standards Review Forum	Yes	
SERC Protection and Controls Subcommittee	Yes	
PPL NERC Registered Affiliates	Yes	
Western Area Power Administration	Yes	
Dominion	Yes	
Bonneville Power Administration	Yes	
PacifiCorp	Yes	
AESI Inc.	Yes	
Chelan County PUD	Yes	

Organization	Yes or No	Question 4 Comment
Idaho Power Company	Yes	
Xcel Energy	Yes	
Independent Electricity System Operator	Yes	
Northeast Utilities	Yes	
Manitoba Hydro	Yes	
ReliabilityFirst	Yes	
Ameren	Yes	
Tacoma Power	Yes	
South Carolina Electric and Gas	Yes	
Entergy Services, Inc. (Transmission)	Yes	
Southwest Power Pool	Yes	
Kansas City Power and Light	Yes	

5. **Do you have any other comments? If so, please provide suggested changes and rationale.**

Summary Consideration: The general section of the comments contain varying issues, some being majority issues that have been addressed in previous postings. There are approximately ten chief concerns. (1) About eight comments supported by 45 stakeholders disagreed that the unit auxiliary transformer (UAT) should be addressed in the standard. The drafting revised the criteria for the UAT to address only those relays on the high-side terminals of the UAT. The drafting team acknowledges the varying configurations of station service supply and agrees that addressing loadability of the UAT is best satisfied at the high-side terminals of the UAT to be responsive to the FERC directive to include them. (2) Approximately five comments represented by about 41 entities disagree with the singe Violation Severity Level (VSL) of Severe. The drafting team contends it has followed the VSL Guidelines and notes that the requirement applies to each load-responsive protective relay. Violations would be evaluated on a case by case basis through the auditing and enforcement process. (3) About six comment supported by 36 stakeholders disagreed with the inclusion or impacts the standard would have on Blackstart generation units and dispersed generation. The drafting team considered these issues and determined that the governing factor should be the application of the Bulk Electric System definition which addresses whether a unit or plant is BES based on individual unit size or site aggregate capacity. (4) Four comments representing about 29 entities disagreed or requested clarity about the use of the phrase “generation interconnection Facilities.” The drafting team addressed this by rephrasing this criterion to avoid confusion with the common understanding. See Question 1 summary and comment responses for more detail. (5) Two comments supported by about 28 individuals desired an approach similar to the PRC-024 standard. The drafting team noted that PRC-024 is based on equipment potentially being damaged and the proposed PRC-025-1 standard criteria achieve its loadability goal in conditions that are not damaging to the generator. (6) Approximately three comments represented by 19 stakeholders suggested using the generator nameplate to reduce the complexity of the criteria. The drafting team addressed this in prior postings and in the above summaries. The proposed PRC-025-1 standard takes into consideration that some generation units may not operate near nameplate capacity; therefore, using a nameplate value would be result in an overly conservative setting. (7) Two comments representing 19 individuals did not agree with the intent of the standard. The drafting team is certain that is has fulfilled its responsibility in meeting the objectives of the project to address load-responsive protective relay loadability for generation Facilities. (8) Three comments supported by about 18 entities expressed concern about the proposed Requirements R7 and R8 in PRC-023-3. The drafting team removed these requirements and added the Distribution Provider and Transmission Owner in PRC-025-1. See the above summaries and comments for more detail. (9) About four comments supported by 11 stakeholders raise concerns about overloading and the application of ANSI standards in relation to the PRC-025-1 standard. The drafting team provided responses to help clarify the differences. Please see the individual responses for greater clarity on overload issues. (10) The last of the chief concerns were noted in three comments represented by 12 individuals who expressed disagreement with a Violation Risk Factor (VRF) of High. The drafting team notes that the assignment of the VRF follows VRF guidelines.

The following summary addresses concerns of two or fewer comments and less than ten individuals. Stakeholders continued to have concerns about the phrase “while maintaining reliable fault protection.” This phrase has been used in previous versions of PRC-023 and the drafting team agrees that it is clear on the expectation. Comments supported by about six entities requested terms in PRC-023-3 to be capitalized to represent NERC glossary definition terms; however, the drafting team did not address these as they are outside the scope of the approved objectives of the project. Another set of comments supported by about eight individuals requested the removal of the “Regional Reliability Organization (RRO) from the standard. The drafting removed this language and to address the potential gap in doing so, increased the Implementation Plan periods by one year. See the summary in Question 2 and individual responses for more detail. Last, single comments asked for clarification of BES generators, minor edits and corrections, Implementation Plan edits, and consideration of the Reliability Standard Audit Worksheet (RSAW) and the Cost Effective Analysis Process (CEAP). See the responses for the RSAW and CEAP for additional detail.

Organization	Yes or No	Question 5 Comment
Pepco Holdings Inc. & Afffiliates	No	
Western Area Power Administration	No	
Duke Energy	No	
PacifiCorp	No	
Idaho Power Company	No	

Organization	Yes or No	Question 5 Comment
Independent Electricity System Operator	No	
Northeast Utilities	No	
South Carolina Electric and Gas	No	
Luminant Generation	No	
Luminant Energy Company LLC	No	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	2) We suggest removing Section 3.2.3 and footnote 1. UAT protection is part of the station service system and should not be in this standard. Remove the UAT from Table 1. The UAT relays are not in the category of "all load-responsive protective relays that are affected by increased generator output in response to system disturbances." The highside overcurrent pickup should not be required to be at 150%. Settings at > & = 115% should be allowed. **Response:** The drafting team contends that the load-responsive protection for any UAT that supplies "running station power" to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made. The specified relays are affected by the conditions being addressed by the standard, and thus need to be addressed. The drafting team has proposed a 150% multiplier for these relays rather than requiring an analysis of the connected loads for depressed voltage; the margin includes consideration for the increased current called for by these

Organization	Yes or No	Question 5 Comment
		loads as well as normal relay setting tolerances. No change made. 3) We believe that the Purpose statement should end "... do not pose a risk of damaging the generator." **Response:** The Purpose statement was modified in the last draft to not be generator specific. The standard addresses generation Facilities in general and the criteria provide reasonable loadability settings that are within the capability of the equipment the standard is addressing. The purpose statement has been modified to clarify risk to associated equipment. Change made. 4) The protection of the generator should be the paramount concern. All ANSI standards for generator and main power transformer protection should be considered to be the ruling guide for protecting the equipment. The minimum allowable settings provided in the table in the draft standard do not factor using time delays in order to provide adequate protection for generators. **Response:** The ANSI/IEEE standards are voluntary and are generally written from an equipment-specific perspective. The drafting team notes that they do, in many cases, mention system performance, and the concerns noted in the ANSI/IEEE standards for system performance do not differ greatly from the criteria proposed in PRC-025-1. The drafting team further notes that the IEEE working groups that develop these standards are considering revisions to the affected standards to align with the Power Plant and Transmission System Protection Coordination document authored by the NERC SPCS. Finally, the drafting team notes that the last two bullets in the Exceptions in PRC-025-1 Attachment 1 address overload protection. No change made. 5) The overload relay that protects the generator from overload may also be the relay that protects the GSU from overload. In the exception list of the draft standard, exception bullet #5 should take precedence over exception bullet #6. **Response:** In the example noted bullet #5 is applicable and bullet #6 is not. Therefore, the relay is exempted under bullet #5. No change made.

Organization	Yes or No	Question 5 Comment
		6) The protection requirements (exception bullet #5) from the ANSI standards need additional recognition, development, and emphasis in the Exceptions section. As written, it appears to be an afterthought. The ANSI standard for synchronous generator protection should be recognized, respected, and not violated. The Table 1 setting specifications which contradict the ANSI standards should be submissive to the ANSI standards and itemized in the exception criteria. Consider removing "extremely" from the "extremely inverse time" description as various vendors call the varying inverse time curve by different names. **Response:** The ANSI/IEEE standards are written from an equipment-specific perspective, and largely disregard system performance concerns. The drafting team notes that they do, in many cases, briefly mention system performance, and the concerns noted in the ANSI/IEEE standards for system performance do not differ greatly from the criteria proposed in PRC-025-1. The drafting team intends that "extremely inverse characteristic" be applied consistently with IEEE C37.112, "IEEE Standard Inverse-Time Characteristic Equations for Overcurrent Relays." No change made. 7) The generator overload protection exception added to Draft 3 for extremely inverse characteristics (fifth exception bullet) is an improvement, but the term "full-load current" needs clarification. Is this the current at normal full-load turbine output and typical PF, the value determined from the generator nameplate MVA at rated voltage, or is it the base or top (no fans, no oil circulation) MVA rating of the GSU? **Response:** The drafting team notes that the phrase full load current refers to rated armature current of the generator. No change made. 8) The wording in the sixth exception bullet of the Exceptions section is too vague. How much of an overload is considered an overload? Many vendor relay curves do not provide characteristics showing the value of current that will time out in 15 minutes. It may be difficult to prove a setting to provide 15 minute delay. Existing relays in service

Organization	Yes or No	Question 5 Comment
		do not have the ability to be set by this criterion. **Response:** The drafting team does not intend to define what an overload is, but instead to exempt schemes that are explicitly designed for overload protection, for which characteristics would be defined for the time period in the bullet. Load-responsive relays that respond otherwise must meet the criteria in Table 1. No change made. 9) The Exceptions section seems to state that the exceptions are allowed only during start up and when off line, which is unacceptable. The exceptions should be allowed at all times. **Response:** The drafting team has revised the exceptions portions of Attachment 1 to address your concerns by inserting a specific numbered exception to adder relay elements that are in service only during startup. Change made. 10) To meet the requirements of table 1 for non-51 relays (distance relays set at approximately 180% of generator MVA) and meet our protection philosophy objectives, we would have to install many new relays for overload protection. **Response:** The drafting team understands that in some cases it may be necessary to replace existing relay equipment. No change made. 11) Determination of the pickup of the distance relays is too complicated. The calculated impedance should be based on generator nameplate MVA and pf only. The requirements make what should be a simple calculation based on generator electrical characteristics into one that will require the relay engineer to find test MW data is not readily unavailable. **Response:** The drafting team intentionally did not reference the calculation to nameplate MVA for the Real Power portion of the calculation because this would result in an overly conservative setting for units that cannot achieve the nameplate capability. The test megawatt data must be reported and should be readily available.

Organization	Yes or No	Question 5 Comment
		No change made. 12) PRC-025 should be revised to "grandfather" existing protection settings that have been proven in practice for many decades not to prematurely remove equipment from service. **Response:** The drafting team has developed the standard in accordance with the regulatory directive concerning generator relay loadability, which is an outcome of the 2003 blackout report. As noted in the NERC document 'Power Plant and Transmission System Coordination' – July 2010, at least 28 generators were tripped on August 14, 2003 by load-responsive phase protection; eight of those by phase distance and 20 more by 51V protection. For many of these generators, the legacy protective equipment had been previously believed to not prematurely remove equipment. No change made. 13) The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, whose tripping would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings for retoration purposes. **Response:** The drafting team contends that during Blackstart conditions the generator may experience extreme voltage and loading swings; therefore, Blackstart units are included and apply to the standard. If such generators are excluded from the applicability of the standard, they may not perform as expected to facilitate system restoration. Also, the drafting team notes that the standard only applies to those Blackstart resources identified in the Transmission Operator's system restoration plan (i.e., SRP). No change made. 14) Voltage-restrained overcurrent relays are notorious for not having a predictable operation time under fault conditions. If they are included in the types of equipment that mis-operated in the August 2003 blackout, they should be required to be replaced with another relay type rather than requiring that the settings be relaxed to the degree

Organization	Yes or No	Question 5 Comment
		specified in the draft standard. **Response:** The drafting team agrees, in general, that these devices are not recommended and, where used, that these devices should be replaced. However, as the drafting team is unable to require that such relays be replaced, applicable criteria are provided. No change made. 15) A High VRF and a Severe VSL seems overly harsh given the compliance feasibility uncertainties. **Response:** The VRF criteria are based on the risk to the system if a requirement is violated, and the VSL criteria are based on the degree of non-compliance. Alleged difficulties in achieving compliance are not a factor in the criteria for either VRFs or VSLs. No change made. 16) Which UATs are proposed to be included, if any, is confusing. Suggest adding diagrams to the reference document. **Response:** The drafting team contends that the load-responsive protection for any UAT that supplies "running station power" to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made. 17) During the webinar there were three slides related to the different trans to Gen interconnections and who is responsible for what; suggest adding and or clarifying these in the reference documents. **Response:** The drafting team thanks you for your comment and notes that load-responsive protective relays applied on "Elements that connect a GSU to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant" (which replaces the previously-used term, "generator interconnection Facility") are covered under the proposed PRC-025-1 standard. Load-responsive protective relays applied on network transmission lines are

Organization	Yes or No	Question 5 Comment
		covered under the proposed PRC-023-3 standard. Please refer to the revised Figures 1, 2, and 3 in the proposed PRC-025-1 Guidelines and Technical Basis for further information on applications. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Northeast Power Coordinating Council	Yes	In PRC-023-3, add “Each” to the beginning of R8.
Response: The drafting team thanks you for your comment and notes that the comment above is no longer relevant because: The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made.		
FirstEnergy	Yes	FE believes that that the term "generator interconnection Facility" should be a NERC defined term in the Glossary since it is used in other standards, ie, PRC-005, or at the very least, be defined within the standard(s). This term is only defined in the Guidelines and Technical Basis. In the Guidelines and Technical Basis, Figure 2 has a typo on the 3rd sentence and should read as follows: If the Distribution Provider or Transmission Owner owns these relay, they are responsible for them under PRC-023.
Response: The drafting team has replaced this term with "Elements that connect a GSU to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant." Change made.		
SERC Protection and Controls Subcommittee	Yes	There were three one-line reference drawings described on the webinar. Suggest adding text to these reference drawings or add descriptive wording in reference documents to better explain responsibilities of relay owners for these various

Organization	Yes or No	Question 5 Comment
		configurations. On the webinar there were repetitive questions about these configurations so this would indicate confusion. Also, would suggest adding another drawing to illustrate when you have a generating station where the GO owns GSU relays and the TO owns relays between the GSU and switchyard to clarify that the TO is only responsible for R7 in PRC023-3 and not R8 since the GSU relays are a GO asset.
Response: The drafting team thanks you for your comments and notes that these figures are already included in the Guidelines and Technical Basis, along with discussion. No change made.		
PPL NERC Registered Affiliates	Yes	: The PPL NERC Registered Affiliates reiterate their concern in regards to the following comments. The Application Guidelines state that the reliability objective of PRC-025 is to cover, "all load-responsive protective relays that are affected by increased generator output in response to system disturbances." Unit Auxiliary Transformers (UAT's) are not in this category and should therefore be excluded from the Applicability of the Standard in Section 3.2.3.The point was made in the 5/15/13 webinar that a decrease in HV system voltage would affect the plant MV voltage as well, causing a proportional increase in current (at constant power draw by plant auxiliary loads) and thereby potentially tripping UAT loadability relays. Reduction in frequency during disturbances will strongly reduce the power draw of pumps and fans, however, so MV current may actually drop despite the HV voltage reduction being experienced. This point of view is supported by the statement in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of '03, so extending PRC-025 applicability to UATs provides only a hypothetical benefit that has not been observed (or has in fact been disproved) in practice. The PPL NERC Registered Affiliates again state that Facilities' UATs in Section 3.2.3 do not belong in this standard as no technical justification has been provided. An investigation and evaluation of the protection systems for unit auxiliary transformers and the UAT's lack of impact on generator loadability should be considered by the SDT.

Organization	Yes or No	Question 5 Comment
		A cost-benefit analysis for generator UATs should be performed to demonstrate that net benefits will result from any such standard before it is proposed. Without such an analysis, the standard may result in costs without a sufficient reliability benefit and may in some cases actually lessen reliability (see item 5 below). **Response:** The drafting team contends that the load-responsive protection for any UAT that supplies "running station power" to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made. 2.) The generator overload protection exception added to Draft 3 for "extremely inverse characteristics" (5th bull-dot) is a major improvement, but the term "full-load current" needs clarification The PPL NERC Registered Affiliates suggest that the SDT state in the Guidelines and Technical Basis that "full-load current" is understood to be the generator nameplate MVA at rated voltage **Response:** The drafting team notes that the phrase full load current refers to rated armature current of the generator. No change made. 3.) The overload protection exception added to Draft 3 for "extremely inverse characteristics" should be applied for UAT's as well if eliminating UAT's in its entirety (per comment #1 above) does not prove feasible. **Response:** The exclusion #7 addresses transformers and is not limited to only GSUs. No change made. 4.) The PPL NERC Registered Affiliates reiterate their concern in regards to the following comments. PRC-025 should be revised to grandfather existing major equipment, similar to the approach recently used for PRC-024. It may not always be possible to develop PRC-025-conforming means of protection without replacing GSUs or UATs; and, in the absence of any compensation to the owner, it would be inappropriate to outlaw equipment that was acceptable under the rules in effect at the

Organization	Yes or No	Question 5 Comment
		time it was installed. **Response:** The drafting team contends that it is possible to provide phase fault backup protection while meeting the requirements of this standard. The drafting team notes that the standard provides multiple options for setting transformer load-responsive phase relays to address this concern. If legacy approaches do not allow the entity to meet the requirement and protection objectives, other approaches may be necessary. To prevent equipment damage from excessive time exposed to overload conditions, the drafting team has included exclusions for dedicated generator and transformer overload protection that operates in time frames appropriate to overload protection. No change made. 5.) The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which NERC requirements have already eliminated any economic rationale for having black-start facilities. Given the numerous CIP standards in effect to afford protection to the critical BS restoration facilities, it would be contradictory to impose a standard that could potentially increase risk of damage to a BlackStart Generator by forcing the BS facility to ride through the disturbance. If that disturbance is a precursor to a blackout, then having BS Resource unavailable to facilitate system restoration would defeat the purpose of designating it as a Blackstart Resource. **Response:** The drafting team contends that during Blackstart conditions the generator may experience extreme voltage and loading swings; therefore, Blackstart units are included and apply to the standard. If such generators are excluded from the applicability of the standard, they may not perform as expected to facilitate system restoration. Also, the drafting team notes that the standard only applies to those Blackstart resources identified in the Transmission Operator's system restoration plan

Organization	Yes or No	Question 5 Comment
		(i.e., SRP). No change made. 6.) The PPL NERC Registered Affiliates reiterate their concern in regards to the following comments. Regarding in particular voltage-restrained overcurrent relays, this type of device is known for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be set as high as specified in the draft standard. **Response:** The drafting team agrees, in general, that these devices are not recommended and, where used, that these devices should be replaced. However, as the drafting team is unable to require that such relays be replaced, applicable criteria are provided. No change made. 7.) Deeming any and all violations of this standard to have a high violation risk factor and a severe violation severity level seems overly harsh, given the compliance feasibility uncertainties expressed above. **Response:** The VRF criteria are based on the risk to the system if a requirement is violated, and the VSL criteria are based on the degree of non-compliance. Alleged difficulties in achieving compliance are not a factor in the criteria for either VRFs or VSLs. No change made. 8.) The compliance uncertainties expressed above also promote the use of risk based compliance approach rather than a zero tolerance policy. Other standards in development (CIP V5 standards) no longer dictate a zero tolerance policy. This concept should be applied to the PRC-025 standard to align with the direction NERC standard development is progressing. **Response:** The drafting team continues to support the proposed draft standard as currently structured. The current draft requirements allow Compliance Enforcement Authorities to take into account an entity's process in connection with the required activities. How compliance will approach a standard is appropriate for the

Organization	Yes or No	Question 5 Comment
		development of the RSAW. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
North American Generator Forum Standards Review Team	Yes	1. UATs should be dropped from the standard. The Application Guidelines state that the reliability objective of PRC-025 is to cover, “all load-responsive protective relays that are affected by increased generator output in response to system disturbances,” but the relays of UATs are not in this category. A disturbance on the HV system would not affect the real or reactive power draws of auxiliary loads, and it was stated in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of ‘03. UATs are stated later in the Application Guidelines to have been included to satisfy a FERC directive (Order No. 733, paragraph 104), but such a move nonetheless appears to be incorrect, particularly in light of NERC’s recent emphasis on the cost justification of reliability standards. **Response:** The drafting team contends that the load-responsive protection for any UAT that supplies “running station power” to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made. 2. The generator overload protection exception added to Draft 3 for extremely inverse characteristics (5th bull-dot) is a major improvement, but the term “full-load current” needs clarification. Is this the current at normal full-load turbine output and typical PF, or the value determined from the generator nameplate MVA at rated voltage, or the base (no fans, no oil circulation) rating of the GSU? **Response:** The drafting team notes that the phrase full load current refers to rated armature current of the generator. No change made. 3. The exception of comment #2 above, which is presently limited to generator overloads, could be applied for UATs as well if eliminating this equipment in its entirety

Organization	Yes or No	Question 5 Comment
		(per comment #1 above) does not prove feasible. **Response:** The exclusion #7 addresses transformers and is not limited to only GSUs. No change made. 4. PRC-025 should be revised to grandfather existing major equipment, similar to the approach recently used for PRC-024. It may not always be possible to develop PRC-025-conforming means of protection without replacing GSUs or UATs; and, in the absence of any compensation to the owner, it would be inappropriate to outlaw equipment that was acceptable under the rules in effect at the time it was installed. **Response:** The drafting team contends that it is possible to provide phase fault backup protection while meeting the requirements of this standard. The drafting team notes that the standard provides multiple options for setting transformer load-responsive phase relays to address this concern. If legacy approaches do not allow the entity to meet the requirement and protection objectives, other approaches may be necessary. To prevent equipment damage from excessive time exposed to overload conditions, the drafting team has included exclusions for dedicated generator and transformer overload protection that operates in time frames appropriate to overload protection. No change made. 5. The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which NERC requirements have already eliminated any economic rationale for having black-start facilities. **Response:** The drafting team contends that during Blackstart conditions the generator may experience extreme voltage and loading swings; therefore, Blackstart units are included and apply to the standard. If such generators are excluded from the

Organization	Yes or No	Question 5 Comment
		applicability of the standard, they may not perform as expected to facilitate system restoration. Also, the drafting team notes that the standard only applies to those Blackstart resources identified in the Transmission Operator's system restoration plan (i.e., SRP). No change made. 6. Regarding in particular voltage-restrained overcurrent relays, this type of device is notorious for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be set as high as specified in the draft standard. **Response:** The drafting team agrees, in general, that these devices are not recommended and, where used, that these devices should be replaced. However, as the drafting team is unable to require that such relays be replaced, applicable criteria are provided. No change made. 7. Deeming any and all violations of this standard to have a high violation risk factor and a severe violation severity level seems overly harsh, given the compliance feasibility uncertainties expressed above. **Response:** The VRF criteria are based on the risk to the system if a requirement is violated, and the VSL criteria are based on the degree of non-compliance. Alleged difficulties in achieving compliance are not a factor in the criteria for either VRFs or VSLs. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Dominion	Yes	PRC-025 -1 Requirement 1: remove the following words: "...while maintaining reliable fault protection." It is not possible for entities to measure or prove this statement. The wording, "while maintaining reliable fault protection", is also included in the Introduction section of PRC-025-1 Guidelines and Technical Basis. The inclusion "describes that the Generator Owner is to comply with this standard while achieving its desired protection goals." Dominion believes that the Generator Owner

Organization	Yes or No	Question 5 Comment
		understands the compliance obligation based upon the requirements of the standards and that the inclusion of the referenced language should be excluded based on the inability of the entity to measure or provide evidence of maintaining reliable fault protection. **Response:** The drafting team contends that the description of the term "while maintaining reliable fault protection" found in the Requirement R1 rationale box adequately conveys the suggested intent. No change made. PRC-025-1: Redline - Page 6 of 18 Table of Compliance Elements; An indication of Lower VSL. Moderate VSL or High VSL needs to be determined with regard to R1. Dominion disagrees with the "all or nothing" approach to VSLs. **Response:** The specified VSL applies separately and individually to each protective relay addressed; therefore it is not possible to grade the VSL. PRC-023-3 Implementation plan; Redline Pages 3-6, R1-R6 the Requirement wording (in the Applicability column) does not exactly match the Requirement wording in the standard. Dominion suggests correcting the wording to match the Standard as written. **Response:** The changed suggested is not editorial and is outside the scope of the supplemental Standards Authorization Request (SAR) as approved by the Standards Committee on January 18, 2013. No change made. PRC-025-1 @ figure 3 - Dominion does not necessarily agree that these lines are part of networked transmission and therefore would not be considered as generator interconnection Facilities. Dominion believes the designation of the lines should be based on registration of the asset owner and will be providing supporting comments in response to the FERC NOPR in docket # RM12-16-000. **Response:** The drafting team asserts that the lines in Figure 3 can be expected to carry network flow, are not used exclusively to export energy directly from a BES generating unit or generating plant to the network, and therefore are not generator

Organization	Yes or No	Question 5 Comment
		interconnection Facilities. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Santee Cooper	Yes	Unit Auxiliary Transformers (UATs) should be removed from this standard (Facilities Section 3.2.3). The purpose of this standard is “To set load-responsive protective relays associated with generation Facilities at a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage.” The intent as stated in the Application Guidelines is to pertain to relays that “are affected by increased generator output in response to system disturbances.” UATs do not fit this criteria. Addressing generating plant unit auxiliary transformers does not have to translate into creating a standard requirement for that equipment. An investigation and evaluation of the protection system for unit auxiliary transformers should be considered by the standard drafting team and deemed to be not related to generator loadability and fulfill the FERC order to address the subject.
Response: The drafting team thanks you for your comments and contends that the load-responsive protection for any UAT that supplies “running station power” to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made.		
JEA	Yes	We would like to see modifications to violation severity levels. While we recognize the SDT is following NERC binary guidelines “pass/fail”, this needs to be improved. The idea that either they “applied” or “did not apply” settings must result in a “severe” violation level does not match the reality that missing 10 out of 20 poses a greater risk to the BES than 1 out of 100.
Response: The drafting team thanks you for your comments and notes the specified VSL applies separately and individually to each protective relay addressed; therefore it is not possible to grade the VSL. No change made.		

Organization	Yes or No	Question 5 Comment
Bonneville Power Administration	Yes	Comments: (1) The use of the term generation interconnection facility without an official definition of the term is concerning to BPA. BPA believes that this term may have different meanings between entities. For example, the entire Bulk Electric System (BES) together with all distribution systems could be considered to be a generation interconnection facility because the purpose of the BES and distribution systems is to interconnect generation to the end user (load). Only under the Guidelines and Technical Basis is a description of what a generator interconnection facility found.BPA is concerned with this approach as it does not give an official definition, and this document is not part of the standard. Additionally, BPA believes the description of generator interconnection facility given in the Guidelines and Technical Basis creates problems. The description provided is that the generation interconnection facility consists of elements between the generator step up transformer (GSU) and the interface with the portion of the BES where the Transmission Owner (TO) takes over the ownership. In many cases the TO owns the line that connects to the generator step up (GSU) transformer and there are no elements between the GSU and the TO. According to this description there is no generation interconnection facility. Due to the ownership arrangements of transmission, generation, and their interconnection facilities throughout the country are highly variable, BPA believes it is not suitable to develop a definition of generation interconnection facilities based on ownership. Such a definition may reflect the ownership arrangements within a particular region while it does not take into account various other arrangements that may exist. BPA recommends for the drafting team to provide a definition of generation interconnection facility that takes into account the various ownership situations that may exist. **Response:** The drafting team has replaced this term with "Elements that connect a GSU to the Transmission system and are used exclusively to export energy directly from a BES generating unit or generating plant." Change made.

Organization	Yes or No	Question 5 Comment
		(2) BPA believes the use of the word associated in the purpose statement of PRC-025-1 as well as in Section 3.2 Facilities is too vague and recommends this term be changed to "whose function is the protection of generation Facilities..." in the purpose statement and Section 3.2 be rewritten to read "3.2 Facilities: The following Bulk Electric System Elements, including those generating units and generating plants identified as Blackstart Resources in the Transmission Operator's system restoration plan:" **Response:** The Purpose statement was modified in the last draft to not be generator specific. The standard addresses generation Facilities in general and the criteria provide reasonable loadability settings that are within the capability of the equipment the standard is addressing. The purpose statement has been modified to clarify risk to associated equipment. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Tennessee Valley Authority	Yes	Is the intent of this standard to identify the lines in their normal configuration and not for contingency events? For example, referring to Figure 3 from the Webinar, if a line is lost, causing the system configuration to change to what is shown in Figure 1, does this mean that the configuration then is considered to fall under R7?
Response: The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. The intent of the standard is based on lines in the normal configuration as being presented in the Figures. No change made.		
ACES Standards Collaborators	Yes	(1) We are not convinced that applicability of PRC-023 R7 and R8 to a Distribution Provider is necessary. It would be unusual for a generator that meets BES definition criteria and compliance registry criteria to be connected to a Distribution Provider.

Organization	Yes or No	Question 5 Comment
		Both criteria require a single generator to be 20 MVA or a plant site to be 75 MVA. From a practical perspective, this could actually be a detriment to reliability by distracting the Distribution Provider from reliability activities because they have to focus on documenting that they do not have any applicable generators connected. How does including the Distribution Provider as an applicable entity benefit reliability? **Response:** The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. Even though it may be unlikely that such a Facility would be connected to a Distribution Provider, the drafting team contends that providing for such a condition in PRC-025-1 would assure that no gaps exist for this situation. (2) The High VRFs for PRC-023 R7 and R8 and PRC-25 R1 and R2 are inconsistent with established NERC criteria. In order to meet the High criteria, a single violation of the requirement "could directly cause or contribute to bulk electric instability, separation or a cascading sequence of failures." A single failure to have a relay set to avoid loadability concerns on a single generator could not lead to instability, separation or cascading without violating other standards. For example, TOP-004-2 R2 already require N-1 operation so a single generator tripping due to relay loadability issues would require at least two standards requirements violations. This cannot be viewed as "directly" causing. **Response:** The drafting team contends that the High VRF is correct, as it fully satisfies the associated criteria from the VRF Guidelines, "… a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system

Organization	Yes or No	Question 5 Comment
		instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, …" Please note that the above criteria include emergency and abnormal conditions under which a loss of a generator that does not meet the loadability requirements could lead to one of these consequences. No change made. (3) We believe the VSLs for PRC-023 R7 and R8 and PRC-25 R1 and R2 are written inconsistent FERC guideline 3 which states that the VSL cannot change the requirement. The plain language of the requirements is written in a plural format as though the requirement considers all relays are considered simultaneously. The VSLs are written such that each relay that is not set appropriately is a separate violation. The VSLs, in essence, change the requirements. For example, the Requirement for PRC-023 R7, states "shall set their load responsive relays," while the VSL essentially modifies the requirement to state "shall set each load responsive relay." We recommend modifying the VSL to be in better alignment with the requirement. **Response:** PRC-025-1 has only one Requirement R1 (not R2) which applies separately and individually to each protective relay (singular) addressed; therefore it is not possible to grade the VSL. No change made. The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. In removing Requirements R7 and R8 from PRC-023-3, the plural use of "relays" is no longer relevant. Change made. (4) The wording in the second sentence of the second paragraph in PRC-023 Attachment C needs to be fixed. There seems to be an extra "Facilities."

Organization	Yes or No	Question 5 Comment
		Response: The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, Attachment C and its Table 1 have been eliminated. The comment is no longer relevant; however, the drafting team updated the similar occurrence in the PRC-025-1 Attachment 1 to “Elements” which more correctly identifies those Facilities which are subject to the standard. Change made. (5) RRO is used throughout both standards. It should be Regional Entity, as stated in NERC’s legal memorandum on the “Use of ‘Regional Reliability Organization’...” The memo states that in general, drafting teams can replace “RRO” with “RE,” provided the functions being performed by the RE are related to their delegated duties. Reliability Standards that refer to REs are legally binding on the REs by operation of Rule 100 of NERC’s Rules of Procedure and by the delegation agreements that NERC has entered into with each RE. **Response:** The reference to “…or other entity as specified by the Regional Reliability Organization (RRO)” has been removed from the standard. Change made. (6) Please strike “other entity as specified by the Regional Reliability Organization (RRO)” that is used throughout Attachment C in PRC-023 and Attachment 1 in PRC-025. It creates compliance uncertainty and provides the Regional Entity far too much discretion. If the purpose is an attempt to document from other standards where the nameplate rating is communicating, we suggest that the drafting team perform a search of the other standards and explicitly document the entities. Otherwise, the Regional Entity, as the standard is worded, could simply decide to move the dates.

Organization	Yes or No	Question 5 Comment
		FERC has ordered NERC to remove regional discretion from standards development, such as the revision of the BES definition. **Response:** The reference to "…or other entity as specified by the Regional Reliability Organization (RRO)" has been removed from the standard. Change made. (7) We appreciate the relay elements that are identified for exclusion in PRC-023 Attachment C. However, we believe that the exclusion should be identified explicitly in Attachment A as well. Attachment A is referenced in applicability section. We are concerned since attachment C is not referenced in the applicability section that exclusion of the relay elements could be lost. **Response:** The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. In removing the previously proposed Requirements R7 and R8 in PRC-023-3, Attachment C and its Table 1 have been eliminated. Change made. (8) We disagree with the applicability of 3.2.5. We not understand how applicability to a distribution collector system for dispersed generation benefits reliability. If a subset of generators in the dispersed generation site trip, it will be a small amount of MWs lost that would not impact the reliability of the Bulk Power System. We can understand inclusion of the main GSU for a large site but not the individual collector elements. **Response:** The drafting team intends that the Applicability for Facilities associated with aggregated generation aligns with the definition of the BES. The drafting team notes that all feeders and individual generators within an aggregated site will require similar

Organization	Yes or No	Question 5 Comment
		load-responsive protective relay settings because they will be challenged by the same loadability during the system conditions being addressed by PRC-025-1; therefore, they will respond as a group, emphasizing that the criteria needs to be applied throughout the aggregated Facility. No change made**.**
Response: The drafting team thanks you for your comments; please see the above responses.		
AESI Inc.	Yes	This draft of the standard uses 0.85 pu transmission system voltage as a benchmark for determining the settings. The latest version of PRC-024-1 defines post-disturbance voltage profile where the system voltage is below 0.85 pu up to 3 seconds. Is there a need to take that into consideration for this standard.
Response: The drafting team has coordinated the concern with the generation verification standard drafting team working on PRC-024-1 under Project 2007-09. The result was that load-responsive protective relay functions (i.e., "…impedance relays, voltage controlled overcurrent relays…") were removed from the PRC-024-1 standard in footnote 1. No change made.		
Chelan County PUD	Yes	1. Please, reconsider the applicaiton to small units that are "black start" or auxiliary units in a BES plant. Application of these requirements to a small (750kW) hydro unit that is black start is problamatic particularly due to the age of many of these units. It is difficult to see where loss of a unit of small size would impact the BES during this type of event. Please, consider a minimum size threshold for units where these requirements would be applicable. Perhaps 20MW as is used in the BES definition would be appropirate. Consider also an exclusion for a small unit, say less than 5MW, that is part of an aggregate plant of larger units that exceeds the 75MW plant threshold. An example is our 750kW hydro unit that is in the plant with ten 25MW units. It seems excessive to apply this to the 750kW unit. **Response:** The drafting team contends that during Blackstart conditions the generator may experience extreme voltage and loading swings; therefore, Blackstart units are included and apply to the standard. If such generators are excluded from the applicability of the standard, they may not perform as expected to facilitate system

Organization	Yes or No	Question 5 Comment
		restoration. Also, the drafting team notes that the standard only applies to those Blackstart resources identified in the Transmission Operator's system restoration plan (i.e., SRP). No change made. The applicability is consistent with the definition of the BES. No change made. 2. UATs should be dropped from the standard. The Application Guidelines state that the reliability objective of PRC-025 is to cover, "all load-responsive protective relays that are affected by increased generator output in response to system disturbances," but the relays of UATs are not in this category. A disturbance on the HV system would not affect the real or reactive power draws of auxiliary loads, and it was stated in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of '03. UATs are stated later in the Application Guidelines to have been included to satisfy a FERC directive (Order No. 733, paragraph 104), but such a move nonetheless appears to be incorrect, particularly in light of NERC's recent emphasis on the cost justification of reliability standards. **Response:** The drafting team contends that the load-responsive protection for any UAT that supplies "running station power" to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made. 3. Clarify UAT and station service transformers. Footnote 1 says "Loss of these transformers will result in removing the generator from service." Does that mean it only applies to SS transformers that loss of will remove a unit from service? What about provisions for backup, multiple transformers and busses? Consider an hydro plant with 4 sation service busses and 12 generating units. Would this standard apply to all? This is very different from thermal stations where a unit would have a dedicated transformer that without its power the unit will trip. Consider liminting this only to transformers where loss would cause a direct trip of a BES unit, or eleminiate

Organization	Yes or No	Question 5 Comment
		UAT ans SS transformers completely per comment 2. **Response:** The drafting team contends that the load-responsive protection for any UAT that supplies “running station power” to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made. 4. The generator overload protection exception added to Draft 3 for extremely inverse characteristics (5th bull-dot) is a major improvement, but the term “full-load current” needs clarification. Is this the current at normal full-load turbine output and typical PF, or the value determined from the generator nameplate MVA at rated voltage, or the base (no fans, no oil circulation) rating of the GSU, or FERC hydro nameplate criteria at best gate? **Response:** The drafting team notes that the phrase full load current refers to rated armature current of the generator. No change made. 5. PRC-025 should be revised to grandfather existing major equipment, similar to the approach recently used for PRC-024. It may not always be possible to develop PRC-025-conforming means of protection without replacing GSUs or UATs; and, in the absence of any compensation to the owner, it would be inappropriate to outlaw equipment that was acceptable under the rules in effect at the time it was installed. **Response:** The drafting team contends that it is possible to provide phase fault backup protection while meeting the requirements of this standard. The drafting team notes that the standard provides multiple options for setting transformer load-responsive phase relays to address this concern. If legacy approaches do not allow the entity to meet the requirement and protection objectives, other approaches may be necessary. To prevent equipment damage from excessive time exposed to overload conditions, the drafting team has included exclusions for dedicated generator and transformer overload protection that operates in time frames appropriate to overload protection.

Organization	Yes or No	Question 5 Comment
		No change made. 6. Deeming any and all violations of this standard to have a high violation risk factor and a severe violation severity level seems overly harsh, given the compliance feasibility uncertainties expressed above. Consider a VSL based on the size of the generating unit or amount of generation that would be lost if the standard were not properly applied. A 20MVA unit would have a much lower impact on the reliability of the BES than a 500MW unit. **Response:** The drafting team contends that the High VRF is correct, as it fully satisfies the associated criteria from the VRF Guidelines, "… a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, …" Please note that the above criteria include emergency and abnormal conditions under which a loss of a generator that does not meet the loadability requirements could lead to one of these consequences. The drafting team also contends that a High VSL is appropriate, in that PRC-025-1 R1 applies separately and individually to each protective relay addressed; therefore it is not possible to grade the VSL; therefore the VSL is binary regardless of the size of the generating unit. No change made. The drafting team contends that the requirements proposed within PRC-025-1 satisfy the associated FERC directive and are appropriate and necessary. Appendix 4B, Section 2 of the NERC Rules of Procedures identify and discuss the basic principles underpinning why and how NERC and the Regional Entities will determine Penalties, sanctions, and Remedial action Directives for violations of the Requirements of the Reliability Standards. By being classified as BES, the facilities involved have been determined to have impact on the reliability of the BES. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		

Organization	Yes or No	Question 5 Comment
Western Farmers Electric Cooperative	Yes	Many generation Facilities, that are part of the Bulk Electric System, became commercial in the 1950's, 1960's, 1970's, 1980's and 1990's. These Facilities should be Grandfathered in. Many of these units, although reliable, it may not be cost effective to obtain compliance with PRC-025-1. Many of these Facilities would be forced to either: (1) implement very expensive upgrades to existing equipment, (2) replace existing equipment, (3) retire the Facility. It's my opinion this is not consistent with the economic rational NERC is attempting to achieve. **Response:** The drafting team contends that it is possible to provide phase fault backup protection while meeting the requirements of this standard. The drafting team notes that the standard provides multiple options for setting transformer load-responsive phase relays to address this concern. If legacy approaches do not allow the entity to meet the requirement and protection objectives, other approaches may be necessary. To prevent equipment damage from excessive time exposed to overload conditions, the drafting team has included exclusions for dedicated generator and transformer overload protection that operates in time frames appropriate to overload protection. No change made. Secondly, the Violation Risk Factor of High, seems extreme because several other standards address generator reliability (Under-frequency, Misoperations, Protection System Maintenance and Testing, Generator Verification). These standards, have resulted in many generation Facilities having undergone relay coordination studies to prevent an occurrence similar to the 2003 "blackout." **Response:** These other standards do not address the conditions being addressed by this standard. No change made.

Organization	Yes or No	Question 5 Comment
Response: The drafting team thanks you for your comments; please see the above responses.		
Xcel Energy	Yes	1) Applicability: In the applicability sections, we suggest you replace the phrase "BES generating unit or generating plant" with "BES generating unit or BES generating plant" to be more clear. **Response:** The drafting team contends that the adjective, "BES" clearly applies to both the generating unit and the generating plant. No change made. 2) M1: We recommend you add "simulation results" as acceptable evidence in Measure M1. (reason: Some people may choose to do PRC023 check in the CAPE simulation.) **Response:** This is existing approved content within PRC-023-2 and outside the scope of this project. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Manitoba Hydro	Yes	(1) Section 3.1.1, PRC-025-01 - the repeated word "Facilities" seems unnecessary. For clarity, remove the last instance of the word "Facilities" in the statement: "Generator Owner that applies load-responsive protective relays at the terminals of Facilities listed in 3.2, Facilities." **Response:** The first occurrence of Facilities should have been "Elements" to refer to the numbered list under the section 3.2, Facilities. Change made. (2) Section 3.2 - it would be useful to add criteria that define which generator units should be included as associated with the BES. Alternatively, should this standard refer to the BES definition for which generator units in this standard will apply to? **Response:** This standard includes all generating units and generating plants that are part of the BES, as established by application of the approved definition of Bulk Electric System (BES). No change made.

Organization	Yes or No	Question 5 Comment
		(3) Section 3.2.5 - It is unclear what elements should be included in this section - Collector lines only? What size (MVA) of generating source that the collector line has to be on to qualify as one of these elements? **Response:** The drafting team intends that the Applicability for Facilities associated with aggregated generation aligns with the definition of the BES. The drafting team notes that all feeders and individual generators within an aggregated site will require similar load-responsive protective relay settings because they will be challenged by the same loadability during the system conditions being addressed by PRC-025-1; therefore, they will respond as a group, emphasizing that the criteria needs to be applied throughout the aggregated Facility. No change made. (4) Implementation Plan, PRC-023-3 - it would be helpful to include the implementation plan within the standard **Response:** The Implementation Plan is posted as a separate document with supporting information for industry consideration. Generally, once the standard is NERC Board of Trustees adopted, the effective date information is re-inserted into the standard; however, an entity should always consult the implementation plan for additional information. No change made. (5) PRC-023-3, Purpose - suggest re-wording to the following "...not interfere with a system operators ability to take remedial action to protect system reliability....". **Response:** The changed suggested is not editorial and is outside the scope of the supplemental Standards Authorization Request (SAR) as approved by the Standards Committee on January 18, 2013. No change made. (6) PRC-023-3, Purpose - capitalize "system operator" because it appears in the Glossary of Terms. **Response:** Capitalizing a term in the standard to represent the NERC Glossary defined term introduces the need for additional technical and industry vetting and is not

Organization	Yes or No	Question 5 Comment
		editorial. The changed suggested is not editorial and is outside the scope of the supplemental Standards Authorization Request (SAR) as approved by the Standards Committee on January 18, 2013. No change made. (7) PRC-023-3, Applicability, Functional Entity - capitalize “protection system” because it appears in the Glossary of Terms. **Response:** Capitalizing a term in the standard to represent the NERC Glossary defined term introduces the need for additional technical and industry vetting and is not editorial. The changed suggested is not editorial and is outside the scope of the supplemental Standards Authorization Request (SAR) as approved by the Standards Committee on January 18, 2013. No change made. (8) PRC-023-3, 4.2.1.3 - ‘BES’ should be written Bulk Electric System (BES) since it is the first appearance of the word. **Response:** The drafting team added exclusion text to the Applicability section 4.2.1.1 which occurs before the above referenced section 4.2.1.3; therefore, the BES acronym has been more fully listed as “Bulk Electric System (BES)” in section 4.2.1.1 rather than 4.2.1.3. Change made. (9) PRC-023-3, 4.2.3.1 - should Transmission lines be written “Transmission lines (and paths)”? **Response:** Making such a change introduces the need for additional technical and industry vetting and is not editorial. The changed suggested is not editorial and is outside the scope of the supplemental Standards Authorization Request (SAR) as approved by the Standards Committee on January 18, 2013. No change made.

Organization	Yes or No	Question 5 Comment
		(10) PRC-023-3, R1, 4 - capitalize the words “power transfer capability” because it appears in the Glossary of Terms. **Response:** This phrase is not a NERC Glossary term and perhaps it is being confused with “Total Transfer Capability” (TTC). No change made. (11) PRC-023 and PRC-025 - capitalize the words “transmission lines” throughout the document(s). **Response:** Capitalizing a term in the standard to represent the NERC Glossary defined term introduces the need for additional technical and industry vetting and is not editorial. The changed suggested is not editorial and is outside the scope of the supplemental Standards Authorization Request (SAR) as approved by the Standards Committee on January 18, 2013. No change made. The phrase “transmission lines” is not used in the proposed PRC-025-1. (12) PRC-023 and PRC-025, D. Compliance 1.1 - the paraphrased definition of ‘Compliance Enforcement Authority’ from the Rules of Procedure is not the standard language for this section. Is there a reason that the standard CEA language is not being used? **Response:** The language used in the standard in section D. Compliance 1.1, “Compliance Enforcement Authority” is the exact definition taken directly from the NERC Rules of Procedure, Appendix 2, Definitions Used in the Rules of Procedure effective March 5, 2013. No change made. (13) PRC-023-3 - Attachment B, Circuits to Evaluate - replace the acronym “BES” with the words “Bulk Electric System”. **Response:** Change made. (14) PRC-023-3 - Attachment B, Criteria, B2 - write out the words for “IROL” then use

Organization	Yes or No	Question 5 Comment
		the acronym thereafter. **Response:** Change made. (15) PRC-023-3 - Attachment C - use the acronym “RRO” after the first instance of the words “Regional Reliability Organization”. **Response:** In removing the previously proposed Requirements R7 and R8 in PRC-023-3, Attachment C and its Table 1 have been eliminated; therefore the comment is no longer relevant. Change made. The reference to “…or other entity as specified by the Regional Reliability Organization (RRO)” has been removed from the standard. Change made. (16) PRC-025-1 - Attachment 1: Relay Settings - use the acronym “RRO” after the first instance of the words “Regional Reliability Organization”. **Response:** The reference to “…or other entity as specified by the Regional Reliability Organization (RRO)” has been removed from the standard. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
ReliabilityFirst	Yes	1) In Attachment 1, it is not clear that the fifth bulleted exception regarding protection systems that detect generator overloads needs or should be as specific as to cite the 7 seconds at 218% of full-load current operating point or characteristic curve. Typically for a fault right on the generator terminals, the current decays in a couple of seconds to around full load current even with the AVR in service. Even during field forcing, it is more likely that the field overcurrent relay would operate rather than a generator overload relay. Therefore, the exclusion does not appear to be needed. If the exclusion is needed, it is recommended that the exclusion be stated in a more general way such as the following: Protection systems that detect generator overloads that are designed to coordinate with the generator short-time capability by utilizing a relay characteristic set to operate no faster than the capability curve and supervised to

Organization	Yes or No	Question 5 Comment
		prevent operation below 115% of full-load current. **Response:** Generator thermal overload protection may be provided by an overcurrent relay as described in clause 4.1.1.2 of IEEE standard C37.102-2006, *IEEE Guide for AC Generator Protection*. This application must be coordinated with the generator thermal capability and would be in conflict with PRC-025-1 unless this exclusion is provided. The drafting team notes that the specific values in exclusion 6 describe a boundary for setting this protection consistent with the generator short time capability and is not prescriptive. No change made. 2) The word ‘Each’ appears to be missing in Requirement R8 of PRC-023-3. ‘Each’ should be inserted at the beginning of the requirement before Transmission Owner and Distribution Provider. **Response:** The comment is no longer relevant because the drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made. 3) Since there are cases where redundant UATs that allow a generator to continue to remain in service when one UAT trips, this may be rationale to revise 3.2.3 of the Applicability section to indicate exclusion for these configurations. Alternatively, it could be addressed in the Guidelines and Technical Basis document. **Response:** The drafting team contends that the load-responsive protection for any UAT that supplies “running station power” to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made.

Organization	Yes or No	Question 5 Comment
		4) The Regional Reliability Organization (RRO) is referenced within both standards and it was ReliabilityFirst's understanding that the term RRO was to be removed from all the standards. In Order 693, Paragraphs 146-148 and paragraph 157 state "The Commission adopts the NOPR proposal to eliminate references to the regional reliability organization as a responsible entity in the Reliability Standards. We conclude that this approach is appropriate because, as explained in the NOPR, such entities are not users, owners or operators of the Bulk-Power System. NERC indicates that it can remove such references, except that the Regional Entity should be identified as the compliance monitor where appropriate." ReliabilityFirst suggests replacing the RRO with the Planning Coordinator (PC) or other registered function the SDT determines to have the wide area view and be responsible for determining what these settings and or values should be. **Response:** The reference to "…or other entity as specified by the Regional Reliability Organization (RRO)" has been removed from the standard. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Ameren	Yes	(1) The generator overload protection exception on page 8 for "extremely inverse characteristics" (5th bullet-dot) is a major improvement, but we believe that the term "full-load current" needs clarification. We ask the SDT, is this current at 100% of the gross MW capability reported to the TP, or the value determined from the generator nameplate MVA at rated voltage, or the base (no fans, no oil circulation) rating of the GSU or the smallest of these? **Response:** The drafting team notes that the phrase full load current refers to rated armature current of the generator. No change made. (2) We believe that Blackstart Resources should be excluded because there is no technical basis for including them. On the contrary, it is more important to assure Blackstart Resources are adequately protected and available for restoration in the

Organization	Yes or No	Question 5 Comment
		extremely unlikely event that a wide-area blackout occurs. Also, we believe that there is no evidence that the tripping of a Blackstart Resources has contributed to widespread outages. In our experience, these resources are below the 20MVA threshold and even if they were on-line and tripped their impact to the BES are minimal. **Response:** The drafting team contends that during Blackstart conditions the generator may experience extreme voltage and loading swings; therefore, Blackstart units are included and apply to the standard. If such generators are excluded from the applicability of the standard, they may not perform as expected to facilitate system restoration. Also, the drafting team notes that the standard only applies to those Blackstart resources identified in the Transmission Operator's system restoration plan (i.e., SRP). No change made**.** (3) In addition to our comments, we also agree with the SERC Protection & Control Subcommittee (PCS) comments and include them by reference. **Response:** Please see the responses to the SERC PCS comments.
Response: The drafting team thanks you for your comments; please see the above responses.		
American Electric Power	Yes	System fed auxiliary transformers whose loss would not result in an instantaneous generating unit trip, and for which operators would have opportunity to reconfigure the plant auxiliary load before a unit trip occurs, should be excluded from this standard. However, if the SDT intends the standard to be applicable to all system fed auxiliary transformers, we recommend removing the text "...that trips the generator either directly or via an interposing/lockout relay" from the standard. This statement is similar to language that entities have used to exclude system fed auxiliary transformers that initiate a process shutdown trip from the scope of other NERC PRC standards. During a disturbance in which system voltage becomes depressed, the generator will

Organization	Yes or No	Question 5 Comment
		respond by increasing excitation in an effort to compensate for the voltage loss. This will result in the generator terminal voltage being greater than the system voltage. For this reason, AEP recommends that settings for applicable relays installed on the generator side of the GSU be based on a generator bus voltage of 1.0 per unit at the generator terminals, rather than a generator bus voltage calculated from 0.85/0.95 per unit of the GSU high-side nominal voltage.
Response: The drafting team contends that the load-responsive protection for any UAT that supplies “running station power” to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made The drafting team acknowledges that the generator terminal voltage during field-forcing will be higher than the transmission system voltage; the drafting team accounted for this in the voltage criteria. No change made.		
Tacoma Power	Yes	Comments 1-4 below pertain to PRC-025-1. 1. Referring to Attachment 1, are phase fault detectors used in current-based local breaker failure schemes excluded from PRC-025-1? **Response:** Yes. The breaker failure relay will assert only if other components fail and is not addressed in the standard; therefore, the associated fault detector is not included. No change made. 2. Referring to Attachment 1, Footnote 3 still has the terms “no-load tap changers (NLTC)” and “on-load tap changers (OLTC).” **Response:** Change made. 3. Referring to page 22 of 68 of the redlined Guidelines and Technical Basis, the first paragraph after “Generator Interconnection Facilities (Synchronous Generators) Phase Distance Relays - Directional Toward Transmission System (21) (Options 14a and 14b),” change “...for these relay...” to “...for these relays...” (There are also other instances of

Organization	Yes or No	Question 5 Comment
		this issue.) **Response:** The editorial suggestion is correct. Change made. 4. Referring to page 20 of 68 of the redlined Guidelines and Technical Basis, would the UATs shown in Figure 6 necessarily be applicable to PRC-025-1? It seems that phase time overcurrent relays applied to UATs like these might not "act to trip the generator directly or via lockout or auxiliary tripping relay." **Response:** The drafting team contends that the load-responsive protection for any UAT that supplies "running station power" to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made. 5. Referring to Attachment C, why are only two of the bulleted exceptions shown in PRC-025-1 Attachment 1 brought over? **Response:** In removing the previously proposed Requirements R7 and R8 in PRC-023-3, Attachment C and its Table 1 have been eliminated. Change made. 6. Referring to page 12 of 13 of the redlined Implementation Plan, change "...were added to address to situations..." to "...were added to address situations..." **Response:** In removing the previously proposed Requirements R7 and R8 in PRC-023-3, the Implementation Plan has been revised to note the specific milestones that are known to improve clarity. Change made. 7. Referring to page 13 of 13 of the redlined Implementation Plan, last row in the table, are references to R7 supposed to be references to R8? Additionally, change "...equally and efficient..." to "...equally efficient..." **Response:** In removing the previously proposed Requirements R7 and R8 in PRC-023-3, the Implementation Plan has been revised to note the specific milestones that are

Organization	Yes or No	Question 5 Comment
		known to improve clarity. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Tri-State G&T	Yes	1. UATs should be dropped from the standard. The Application Guidelines state that the reliability objective of PRC-025 is to cover, "all load-responsive protective relays that are affected by increased generator output in response to system disturbances," but the relays of UATs are not in this category. A disturbance on the HV system would not affect the real or reactive power draws of auxiliary loads, and it was stated in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of '03. UATs are stated later in the Application Guidelines to have been included to satisfy a FERC directive (Order No. 733, paragraph 104), but such a move nonetheless appears to be incorrect, particularly in light of NERC's recent emphasis on the cost justification of reliability standards. **Response:** The drafting team contends that the load-responsive protection for any UAT that supplies "running station power" to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made. 2. PRC-025 should be revised to grandfather existing major equipment, similar to the approach recently used for PRC-024. It may not always be possible to develop PRC-025-conforming means of protection without replacing GSUs or UATs; and, in the absence of any compensation to the owner, it would be inappropriate to outlaw equipment that was acceptable under the rules in effect at the time it was installed. **Response:** The drafting team contends that it is possible to provide phase fault backup protection while meeting the requirements of this standard. The drafting team notes that the standard provides multiple options for setting transformer load-responsive phase relays to address this concern. If legacy approaches do not allow the entity to

Organization	Yes or No	Question 5 Comment
		meet the requirement and protection objectives, other approaches may be necessary. To prevent equipment damage from excessive time exposed to overload conditions, the drafting team has included exclusions for dedicated generator and transformer overload protection that operates in time frames appropriate to overload protection. No change made. 3. The applicability of PRC-025 should exclude small gensets that are NERC-registered solely due to being black start-capable, the tripping of which would not meaningfully affect the ability of the system to ride through Disturbances. It would be best to allow such units to maintain their present loadability relay settings, if they are consistent with a reasonable coordination study, rather than mandate upgrades that augment the degree to which NERC requirements have already eliminated any economic rationale for having black-start facilities. **Response:** The drafting team contends that during Blackstart conditions the generator may experience extreme voltage and loading swings; therefore, Blackstart units are included and apply to the standard. If such generators are excluded from the applicability of the standard, they may not perform as expected to facilitate system restoration. Also, the drafting team notes that the standard only applies to those Blackstart resources identified in the Transmission Operator's system restoration plan (i.e., SRP). No change made. 4. Regarding in particular voltage-restrained overcurrent relays, this type of device is notorious for not having a predictable operation time under fault conditions. If they did mis-operate in the August 2003 blackout they should be changed-out rather than requiring that the settings be set as high as specified in the draft standard. **Response:** The drafting team agrees, in general, these devices are not recommended, and where used, that these devices should be replaced. However, as the drafting team is unable to require that such relays be replaced, applicable criteria are provided. The threshold criteria in PRC-025-1 are necessary to prevent tripping from generator load-responsive protective relays for short-time overloads during the field-forcing

Organization	Yes or No	Question 5 Comment
		conditions of the generator, for which the equipment was designed. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Ingleside Cogeneration LP	Yes	In the previous posting, the project team requested our estimated compliance costs and comments on the RSAW. Both of these projects are components of risk-based compliance - which Ingleside Cogeneration LP fully supports. However, it appears that these are not considerations at all in the latest postings. We are not sure what has changed in the intellectual basis of risk-based compliance, but it seems we have taken a step backwards. The rationale for far too many of the project team's consideration of comments was that FERC Order 733 mandated some action. Since FERC has been generally supportive of the risk-based initiative, this type of response is inconsistent with their position in our view.
Response: The Cost Effective Analysis Process (CEAP) in the draft 3 posting of PRC-025-1 was an initial pilot of the program for only Phase II of the CEAP. The drafting team was provided summary information which did not reveal substantive reasons for changing the way the team developed PRC-025-1. Please see the Pilot CEAP Report on the Project 2010-13.2 project page (http://www.nerc.com/pa/Stand/Pages/Project-2010-13-2-Phase-2-Relay-Loadability-Generation.aspx). No change made. Also, NERC Compliance provided the industry comments to the drafting team from the RSAW which was posted contemporaneously with the draft 3 posting of PRC-025-1. Revisions made to the RSAW were provided to NERC Compliance for consideration and reposting; however, NERC Compliance elected to wait as they are currently working toward a more defined process for RSAW posting and commenting. No change made.		
Entergy Services, Inc. (Transmission)	Yes	The implementation plan may be challenging to meet and an alternative implementation plan may need to be provided based on the population of load-responsive protective relays determined affected by this standard and the subset of which that will require replacement relays. Additional resources will be required to (1) determine the population of load-responsive relays at each generating station,

Organization	Yes or No	Question 5 Comment
		(2) determine the settings of the existing load-responsive relays, (3) calculate load-responsive relay settings per the reliability standard, (4) compare the existing load-responsive relay settings to the calculated load-responsive relay settings to determine the population which are acceptable as-is, the population that require a settings change, and the population that requires replacement, (5) schedule the population of load-responsive relays for settings change, (6) order replacement load-responsive relays for the population determined incapable of meeting the reliability standard and schedule relay replacement. The resulting calculations and set-point datasheets will form the basis for the load-responsive relay settings and evidence for meeting the standard’s requirements.
Response: The drafting team thanks you for your comments and contends that the Implementation Plan establishes the deadlines by which the standards must be implemented. Individual steps to achieve implementation are left to the entity to determine and manage. No change made.		
Public Service Enterprise Group	Yes	The SDT needs to confirm that UATs that are energized from the system (not the GSU) at high-side voltages that are below 100 kV are part of the BES before imposing standards on UAT load-responsive relay settings.
Response: The drafting team thanks you for your comments and notes that NERC Reliability Standards may be applicable to equipment that is not part of the BES if necessary to support reliable operation of the bulk power system. No change made.		
Seminole Electric Cooperative Inc.	Yes	Seminole Electric reasons that the NERC SDT has not provided sufficient evidence to warrant a High VRF and a Severe VSL for penalties associated with proposed Standard PRC-025-1.
Response: The drafting team contends that the High VRF is correct, as it fully satisfies the associated criteria from the VRF		

Organization	Yes or No	Question 5 Comment
Guidelines, "… a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, …" Please note that the above criteria include emergency and abnormal conditions under which a loss of a generator that does not meet the loadability requirements could lead to one of these consequences. The drafting team also contends that a High VSL is appropriate, in that PRC-025-1 R1 applies separately and individually to each protective relay addressed; therefore it is not possible to grade the VSL. No change made.		
Flathead Electric Cooperative	Yes	Do not support including Elements utilized in the aggregation of dispersed power producing resources. This seems to have the potential to rope very small generators into significant compliance burdens for very little reliability benefit.
Response: The drafting team intends that the Applicability for Facilities associated with aggregated generation aligns with the definition of the BES. The drafting team notes that all feeders and individual generators within an aggregated site will require similar load-responsive protective relay settings because they will be challenged by the same loadability during the system conditions being addressed by PRC-025-1; therefore, they will respond as a group, emphasizing that the criteria needs to be applied throughout the aggregated Facility. No change made.		
Southwest Power Pool	Yes	For the sake of clarity, I would suggest adding the phrase 'to the generator' at the end of the Purpose of PRC-025-1. This is implied in the existing language but it wouldn't hurt to add this and specifically indicate what damage you're referring to. **Response:** The Purpose statement was modified in the last draft to not be generator specific. The standard addresses generation Facilities in general and the criteria provide reasonable loadability settings that are within the capability of the equipment the standard is addressing. The purpose statement has been modified to clarify risk to associated equipment. Change made. For consistency within the requirements and between the requirement and corresponding measure in this situation, please add 'Each' at the beginning of Requirement R8. This makes R8 consistent with the rest of the requirements and with

Organization	Yes or No	Question 5 Comment
		Measure M8. **Response:** The drafting team has decided to integrate Transmission Owner and Distribution Provider into the proposed PRC-025-1, rather than adding Requirement R7 and R8 to the proposed PRC-023-3 to establish a bright line between the two standards. The owner of load-responsive protective relays applied to generation-related Facilities will be in PRC-025 and owner of load-responsive protective relays network-related Facilities in PRC-023 regardless of ownership of the Facilities. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Kansas City Power and Light	Yes	Generators and Generator step up transformers are critical elements of the BES and have very long lead times for replacement or major repair. However, the Transmission Relay load ability standard has less stringent load ability requirements than the Generator load ability standard. Transmission lines are allowed to trip at 150% of four hour rating or 115% of 15 minute rating. We do not understand the newly added portion of the Exceptions of PRC-025-1 why is there only the option of a specific curve type specified for the Generator. There is no exception available for the GSU or Aux Transformers therefore the GSU and Aux transformers that would allow them to be set like large auto transformers it is not our belief that these transformers should be required to be set with more Stringent settings. We believe that these transformers should be set similar to the large auto transformers.
Response: The drafting team thanks you for your comment and notes that Exclusion #7 addresses transformers and is not limited to only GSUs. No change made. This exclusion is different than Exclusion #6 (applicable to generators) to reflect the differences in thermal overload capability. The drafting team asserts the time frames in these exclusions are therefore appropriate. No change made.		
MRO NERC Standards		The NSRF remains concerned that the proposed calculations for the distance relays will

Organization	Yes or No	Question 5 Comment
Review Forum		adversely affect reliability of the BES by requiring generators to pull back distance reaches too far which could lead to reduced rely coverage (at least for backup relaying) or longer delays for coordination. Some sample calculations performed by NSRF members show that distance reaches need to be pulled back more than 30%. The NSRF members believe that this is most likely due to the more conservative relay load limit angle calculations at 30 degrees rather than former MidContinent Area Power Pool (MAPP) criteria which used line Maximum Torque Angle calculations which typically averaged near 70 - 85 degrees. Sample MAPP Relay Load Limit Calculation: (0.85*kV)^2 / (Z1max*cos(max torque angle - line power factor angle)NSRF sample calculations show that many generators may require 21 distance setting changes based upon this proposed standard, potentially resulting in potential reductions of relay backup coverage for lines leaving some generating stations. This will put a much higher risk and responsibility on the TO too have extremely reliable protection for the lines. We will no longer be able to trip the generator off in a backup mode if the TO does not clear the phase fault at end of line. This appears to conflict with R1, unless the standard is mandating the installation of additional equipment such as redundant relays systems to maintain reliable fault protection. The NSRF would ask the NERC Standard drafting team to work with NSRF members to help verify the basis for the new calculations and if this does in fact reduce relay coverage or require entities to install additional relaying to maintain system reliability as mandated in R1.

Response: The drafting team thanks you for your comments and notes the basis for the calculations for the generator protective relays in proposed PRC-025-1 is well established by observed behavior during disturbances and by simulations, and the observed behavior verifies the simulations. The various options (…a, …b, and …c) represent varying degrees of calculation complexity, wherein the most conservative criterion represents a very simple calculation, and the complexity increases as the criteria becomes less conservative. No change made.

The drafting team contends that it is possible to provide phase fault backup protection while meeting the requirements of this standard. The drafting team notes that the standard provides multiple options for setting transformer load-responsive phase

Organization	Yes or No	Question 5 Comment
relays to address this concern. If legacy approaches do not allow the entity to meet the requirement and protection objectives, other approaches may be necessary. To prevent equipment damage from excessive time exposed to overload conditions, the drafting team has included exclusions for dedicated generator and transformer overload protection that operates in time frames appropriate to overload protection. No change made.		
Texas Reliability Entity		Texas RE generally supports this standard as written, other than the use of the term *Regional Reliability Organization* in Table 1 as described above. Our other comments are provided for consideration by the drafting team.
Response: The reference to "…or other entity as specified by the Regional Reliability Organization (RRO)" has been removed from the standard. Change made.		
Exelon and its affiliates		The Constellation Energy Nuclear Generation (CENG) NERC Registered Affiliates reiterate their concern in regards to the following comments. The Application Guidelines state that the reliability objective of PRC-025 is to cover, "all load-responsive protective relays that are affected by increased generator output in response to system disturbances." Section 3.2.3 of PRC-025-1 requires clarification simply because the Unit Auxiliary Transformers (UAT's) are not necessarily directly connected to the generator, but there are indirect link to the generator operation. The UAT's are ok to be included to the applicability of this standard, but section 3.2.3 could use more detailed explanation. Moreover, the webinar on 5/15/13 pointed out that a decrease in HV system voltage would affect the plant MV voltage as well, causing a proportional increase in current (at constant power draw by plant auxiliary loads) and thereby potentially tripping UAT loadability relays. Reduction in frequency during disturbances will strongly reduce the power drawn of pumps and fans, however, so MV current may actually drop despite the HV voltage reduction being experienced. This point of view is supported by the statement in the 12/13/2012 webinar that UAT relay trips are not known to have caused the loss of any generation units during the northeast blackout of '03, so extending PRC-025 applicability to UATs provides only a hypothetical benefit that has not been observed (or has in fact been disproved) in

Organization	Yes or No	Question 5 Comment
		practice. CENG state that Facilities, UAT's in Section 3.2.3 is appropriate to include it, but there need to be a specific explanation as to the affect of MW due to grid disturbance affect the generator output. An investigation and evaluation of the protection systems for unit auxiliary transformers and the UAT's lack of impact on generator loadability should be considered.
Response: The Purpose statement was modified in the last draft to not be generator specific. The standard addresses generation Facilities in general and the criteria provide reasonable loadability settings that are within the capability of the equipment the standard is addressing. The purpose statement has been modified to clarify risk to associated equipment. Change made. The drafting team contends that the load-responsive protection for any UAT that supplies "running station power" to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made.		
Consumers Energy	Yes	Page 3 of 20, 3.2: Blackstart Resources that would not otherwise be defined as part of the BES should not be included in the Facilities. Although voltage swings will occur during restarting of the system, the detailed planning to control the electrical paths and the placement of operating personnel to key substation locations preclude the need for loadability criteria for these small generators. Blackstart Resources should be removed from the list of Facilities. **Response:** The drafting team contends that during Blackstart conditions the generator may experience extreme voltage and loading swings; therefore, Blackstart units are included and apply to the standard. If such generators are excluded from the applicability of the standard, they may not perform as expected to facilitate system restoration. Also, the drafting team notes that the standard only applies to those Blackstart resources identified in the Transmission Operator's system restoration plan (i.e., SRP). No change made.

Organization	Yes or No	Question 5 Comment
		Page 8 of 20, Exceptions: The Drafting Team has added one bullet item to and modified one in the list of Exceptions. The first one recognizes the need to operate within generator short time capabilities and is acceptable. The second exclusion attempts to place an operator response time of 15 minutes or greater to a transformer overload condition. While a system disturbance may continue for extended periods, we believe that the 15 minute time frame far exceeds the practical relay operate time of standard electromechanical, static or digital protective relays. The operate time characteristics for most relays, as drawn on the manufacturers' time-current curves, are much faster than 15 minutes. Traditional relay curves are drawn to begin at 1.5 times pickup. The maximum relay operate times at that defined relay pickup is typically in the 2-5 minute range. Considering that the relay curves do not extend beyond a few minutes, a time specification beyond 5 minutes is unrealistic. The wording of the last exception should be changed to exclude: "Protection systems that detect transformer overloads and are designed to respond in time periods which are greater than 2 minutes" **Response:** The drafting team intends to exempt schemes that are explicitly designed for overload protection, for which characteristics would be defined for the time period in the bullet. Load-responsive relays that respond otherwise must meet the criteria in Table 1. The proposed change to 2 minutes in the referenced exclusion may not be sufficient to allow the system voltage to recover for the conditions being addressed by this standard. No change made. Page 14-15 of 20, 8a, 8b and 8c: The standard Pickup Setting Criteria for the step-up transformer overcurrent element pickup is stated as 115% of any of three calculated currents. In these cases the step-up transformer can probably withstand the high currents for a short period of time, however all generators cannot be expected to operate up to this percent current. It should be recognized that the control functions set to protect the generator short time capabilities may supersede the operation of the overcurrent element. Therefore any dynamic modeling of a generator must include the excitation limitations. If the overcurrent element is set to operate to protect the generator, then the pickup criteria must be changed to limits of the particular

Organization	Yes or No	Question 5 Comment
		generator. A fourth alternative 8d should be created to recognize generator limits and allow for setting the pickup and timing of the overcurrent element to protect the generator. **Response:** Proposed PRC-025-1 is based on system conditions where the generator is expected to provide full field forcing until such a time as the excitation system controls act to bring the generator back to within its steady state capability curve. Options 8a, 8b, and 8c establish that the GSU shall not trip for the identical conditions for which the generator criteria are established. No change made. Page 17 of 20, 13a and 13b: Unit auxiliary transformers are normally sized to carry all of the station power loads for the expected range of the generator operating voltage. A transformer high side overcurrent relay should be set to allow the transformer loading, with margin. Since the standard is based upon “widely depressed” system voltage and the standard recognizes that the generator will be supplying VARs to the system, the generator terminal voltage will most likely be at or above rated. The pickup criteria are unnecessarily complicated by the inclusion of 13b. We recommend retaining 13a and the removal of 13b. **Response:** The drafting team contends that the load-responsive protection for any UAT that supplies “running station power” to the plant, such that tripping of the UAT will cause the generator to trip, should be addressed by the draft standard. The drafting team has revised the Table 1 criteria for UAT protection in the Standard and the Guidelines and Technical Basis discussion accordingly. Change made. The UAT can be connected at a variety of points; for system-connected UAT, the UAT primary winding will see approximately 0.85 p.u. voltage; for unit-connected UAT, the drafting team estimates that this voltage will be 0.9 to 0.95 p.u. voltage. The drafting team has proposed a 150% margin for these relays rather than requiring an analysis of the connected loads for depressed voltage; the margin includes consideration for the increased current called for by these loads as well as normal relay

Organization	Yes or No	Question 5 Comment
		setting tolerances. Some entities have indicated that 13b may be useful; therefore the drafting team has decided to not remove it. No change made.
Response: The drafting team thanks you for your comments.		

END OF REPORT

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. The Standards Committee approved the Supplemental SAR regarding PRC-023-2 for posting on January 16-17, 2013.
2. The Supplemental SAR was posted for a 45-day informal comment period from January 25, 2013 to March 11, 2013 along with a red-lined Draft 1 of the revised standard.
3. Draft 2 of the revised standard was posted for a 30-day formal comment period from April 25, 2013 to May 24, 2013.

Description of Current Draft

The Generator Relay Loadability Standard Drafting Team (GENRLOSDT) is posting Draft 3 of PRC-023-3 – Transmission Relay Loadability for a 45-day formal comment period and initial ballot.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	April 2013
45-day Formal Comment Period and Initial Ballot	June 2013
10-day Recirculation Ballot	August 2013
BOT adoption	November 2013
File with FERC	December 2013

Effective Dates

See PRC-023-3 Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”	Errata

Version	Date	Action	Change Tracking
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	TBD	Clarify applicability for consistency with PRC-025-1 and other minor corrections	Supplemental SAR (Project 2010-13.2)

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.

No new or revised term is being proposed.

A. Introduction

1. **Title: Transmission Relay Loadability**
2. **Number:** PRC-023-3
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. Functional Entity

4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinator

4.2. Circuits

4.2.1 Circuits Subject to Requirements R1 – R5

4.2.1.1 Transmission lines operated at 200 kV and above, except lines that are used exclusively to export energy directly from a Bulk Electric System (BES) generating unit or generating plant to the network.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

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

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network.

Effective Dates: See Implementation Plan.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. 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] [Time Horizon: Long Term Planning]*.

Criteria:

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).

2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).

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:

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

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 Requirement R1, criterion 3, using the full line inductive reactance.

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).

6. Not used.

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.

[1] 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.

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.

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.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays 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.

10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 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, for at least 15 minutes to provide time 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 set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

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:

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

b. 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.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

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.

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[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 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]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-3 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-3, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

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

The Compliance Enforcement Authority shall keep the last audit record 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.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated.	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met

Requirement	Lower	Moderate	High	Severe
		(part 6.2)		6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. 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, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

PRC-023-3 — 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).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

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

2.1. 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 except as noted in section 1.6

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

2.4. Not used.

2.5. Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-3 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

    i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

    ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

    iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

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. The Standards Committee approved the Supplemental SAR regarding PRC-023-2 for posting on January 16-17, 2013.
2. The Supplemental SAR was posted for a 45-day informal~~formal~~ comment period from~~on~~ January 25, 2013 to March 11, 2013 along with a red-lined Draft 1 of the revised standard.
3. Draft 2 of the revised standard was posted for a 30-day formal comment period from April 25, 2013 to May 24, 2013.

Description of Current Draft

The Generator Relay Loadability Standard Drafting Team (GENRLOSDT) is posting Draft 3~~1~~ of PRC-023-3 – Transmission Relay Loadability for a 45~~30~~-day formal comment period and initial ballot.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	April 2013
45-day Formal Comment Period and Initial Ballot	June~~August~~ 2013
10-day Recirculation Ballot	August~~October~~ 2013
BOT adoption	November 2013
File with FERC	December 2013

Effective Dates

See PRC-023-3 Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”	Errata

Version	Date	Action	Change Tracking
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	TBD	Clarify applicability for consistency with PRC-025-1 and other minor corrections	Supplemental SAR (Project 2010-13.2)

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.

No new or revised term is being proposed.

A. Introduction

1. **Title: Transmission Relay Loadability**

2. **Number:** PRC-023-3

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. Functional Entity

4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1~~, 4.2.3, or 4.2.4~~ *(Circuits Subject to Requirements R1 – R5~~, R7, and R8~~).*

4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).*

4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1~~, 4.2.3, or 4.2.4~~ *(Circuits Subject to Requirements R1 – R5~~, R7, and R8~~)*, provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinator

4.2. Circuits

4.2.1 Circuits Subject to Requirements R1 – R5

4.2.1.1 Transmission lines operated at 200 kV and above, except lines that are used exclusively to export energy directly from a Bulk Electric System (BES) generating unit or generating plant to the network.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

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

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network.

~~4.2.3 Circuits Subject to Requirement R7~~

~~4.2.3.1 Transmission lines that are used solely to export energy directly from a BES generating unit or generating plant to the network.~~

~~4.2.4 Circuits Subject to Requirement R8~~

~~4.2.4.1 Transformers with low voltage terminals connected below 200 kV, including generator step-up transformers, that are used solely to export energy directly from a BES generating unit or generating plant to the network.~~

5. **Effective Dates:** See Implementation Plan.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. 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] [Time Horizon: Long Term Planning]*.

Criteria:

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).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).
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:
   - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
   - 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.
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.

[1] 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.

- 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with Requirement R1, criterion 3, using the full line inductive reactance.

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).

6. Not used.

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.

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.

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.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays 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.

10.1 Set load -responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 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, for at least 15 minutes to provide time 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 set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

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:

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[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

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

b. 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.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

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. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 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]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-3 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-3, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

~~**R7.** Each Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator interconnection Facility. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*.~~

~~**R8.** Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator step-up transformer. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*.~~

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

~~**M7.** Each Transmission Owner and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) to show that each of its generator interconnection Facility relays is set according to one of the criteria in Attachment C. (R7)~~

~~**M8.** Each Transmission Owner and Distribution Provider shall have evidence (e.g., summaries of calculations, spreadsheets, simulation reports, or setting sheets) to show that each of its generator step-up transformer relays is set according to one of the criteria in Attachment C. (R8)~~

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority~~Monitoring Responsibility~~

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

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5~~, R7, and R8~~ for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

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

The Compliance Enforcement Authority shall keep the last audit record 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.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES~~Bulk Electric System~~ for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated.	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must

Requirement	Lower	Moderate	High	Severe
		(part 6.2)		comply with the standard and met 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.
~~R7~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The responsible entity did not set one of its generator interconnection Facility relays in accordance with the criteria in Attachment C.~~
~~R8~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The responsible entity did not set one of its generator step-up transformer relays in accordance with the criteria in Attachment C.~~

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. 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, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

PRC-023-3 — 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).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

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

2.1. 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 except as noted in section 1.6

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

2.4. Not used.

~~**2.4.** Protective relays applied at the terminals of generation Facilities in accordance with NERC Reliability Standard PRC-025-1 or its successor(s).~~

2.5. Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-3 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System~~BES~~.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL),~~IROL,~~ where the IROL was determined in the planning horizon pursuant to FAC-010.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

   i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

   ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

   iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

~~PRC-023-3 — Attachment C~~

~~The following criteria shall be used to set load-responsive relays on generator interconnection Facilities and generator step-up transformers.~~

~~This standard does not require the responsible entity to use any of the protective functions listed in Table 1. Each responsible entity that applies load-responsive protective relays on Facilities listed in 4.2.3 and 4.2.4, Facilities shall use one of the following Options 1-12 in Table 1, Relay Loadability Evaluation Criteria ("Table 1"), to set each load-responsive protective relay element according to its application and relay type. The bus voltage is based on the criteria for the various applications listed in Table 1.~~

~~Relay pickup setting criteria values related to synchronous generators are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and the unit's Reactive Power capability, in megavoltampere-reactive (Mvar), is determined by calculating the MW value based on the unit's nameplate megavoltampere (MVA) rating at rated power factor. If different seasonal capabilities are reported, the maximum capability shall be used for the purposes of this standard.~~

~~Relay pickup setting criteria values related to asynchronous generators (including inverter-based installations) are derived from the site's aggregate maximum complex power capability, in MVA, as reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), including the Mvar output of any static or dynamic reactive power devices.~~

~~For the application case where synchronous and asynchronous generator types are combined on a generator step-up transformer or on a generator interconnection Facility, the pickup setting criteria shall be determined by vector summing the pickup setting criteria of each generator type, and using the bus voltage for the given synchronous generator application and relay type.~~

~~Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.~~

~~Any relay elements that are in service only during start up, when the generator is disconnected, or when other Protection System components fail are excluded. Examples of exclusions include, but are not limited to, the following:~~

- ~~Load-responsive protective 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),~~
- ~~Phase fault detector relay elements employed to supervise other load-responsive phase distance elements (in order to prevent false operation in the event of a blown secondary fuse) provided the distance element is set in accordance with the criteria outlined in the standard,~~

~~Table 1~~

~~The Table is structured and formatted to aid the reader with identifying an option for a given load-responsive protective relay.~~

~~The first column identifies the application (e.g., generator step-up transformers and generator interconnection Facilities). Dark blue horizontal bars, excluding the header which repeats at the top of each page, demarcate the various applications.~~

~~The second column identifies the load-responsive protective relay (e.g., 21, 51, or 67) according to the applied application in the first column. A light blue horizontal bar between the relay types is the demarcation between relay types for a given application. These light blue bars will contain no text.~~

~~The third column uses numeric and alphabetic options (i.e., index numbering) to identify the available options for setting load-responsive protective relays according to the application and applied relay type. Another, shorter, light blue bar contains the word "OR," and reveals to the reader that the relay for that application has one or more options (i.e., "ways") to determine the bus voltage and pickup setting criteria in the fourth and fifth column, respectively. The bus voltage column and pickup setting criteria columns provide the criteria for determining an appropriate setting.~~

~~The table is further formatted by alternately shading groups of relays within a similar application. Also, intentional buffers were added to the table such that similar options would be paired together on a per page basis. Note that some applications may have additional pairing that might occur on adjacent pages.~~

<table>
<tr><th colspan="5">~~Table 1: Relay Loadability Evaluation Criteria~~</th></tr>
<tr><th>~~Application~~</th><th>~~Relay Type~~</th><th>~~Option~~</th><th>~~Bus Voltage~~[5]</th><th>~~Pickup Setting Criteria~~</th></tr>
<tr><td rowspan="6">~~Generator step-up transformer connected to synchronous generators~~</td><td rowspan="5">~~Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of GSU~~
~~If the relay is installed on the high-side of GSU use Option 7~~</td><td>~~1a~~</td><td>~~Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer~~</td><td>~~The impedance element shall be set less than the calculated impedance derived from 115% of:~~
~~(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and~~
~~(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor~~</td></tr>
<tr><td colspan="3">~~**OR**~~</td></tr>
<tr><td>~~1b~~</td><td>~~Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)~~</td><td>~~The impedance element shall be set less than the calculated impedance derived from 115% of:~~
~~(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and~~
~~(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor~~</td></tr>
<tr><td colspan="3">~~**OR**~~</td></tr>
<tr><td>~~1c~~</td><td>~~Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing~~</td><td>~~The impedance element shall be set less than the calculated impedance derived from 115% of:~~
~~(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and~~
~~(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation~~</td></tr>
<tr><td colspan="4">~~**The same application continues on the next page with a different relay type**~~</td></tr>
</table>

~~[5] Calculations using the generator step-up (GSU) transformer turns ratio shall use the actual tap that is applied (i.e., in service) for GSU transformers with deenergized tap changers (DETC). If load tap changers (LTC) are used, the calculations shall reflect the tap that results in the lowest generator bus voltage. When the criterion specifies the use of the GSU transformer's impedance, the nameplate impedance at the nominal GSU turns ratio shall be used.~~

~~Table 1: Relay Loadability Evaluation Criteria~~				
~~**Application**~~	~~**Relay Type**~~	~~**Option**~~	~~**Bus Voltage**~~[5]	~~**Pickup Setting Criteria**~~
~~Generator step-up transformer connected to synchronous generators~~	~~Phase time overcurrent relay (51) – installed on generator-side of GSU~~ ~~If the relay is installed on the high-side of GSU use Option 8~~	~~2a~~	~~Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer~~	~~The overcurrent element shall be set greater than 115% of the calculated current derived from:~~ ~~(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and~~ ~~(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor~~
		~~**OR**~~		
		~~2b~~	~~Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)~~	~~The overcurrent element shall be set greater than 115% of the calculated current derived from:~~ ~~(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and~~ ~~(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor~~
		~~**OR**~~		
		~~2c~~	~~Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing~~	~~The overcurrent element shall be set greater than 115% of the calculated current derived from:~~ ~~(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and~~ ~~(2) Reactive Power output – 100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation~~
	~~**The same application continues on the next page with a different relay type**~~			

~~Table 1: Relay Loadability Evaluation Criteria~~

~~Application~~	~~Relay Type~~	~~Option~~	~~Bus Voltage~~[5]	~~Pickup Setting Criteria~~
~~Generator step-up transformer connected to synchronous generators~~	~~Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of GSU~~ ~~If the relay is installed on the high-side of GSU use Option 9~~	~~3a~~	~~Generator bus voltage corresponding to 0.95 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer~~	~~The overcurrent element shall be set greater than 115% of the calculated current derived from:~~ ~~(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and~~ ~~(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor~~
		~~OR~~		
		~~3b~~	~~Calculated generator bus voltage corresponding to 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer (including the transformer turns ratio and impedance)~~	~~The overcurrent element shall be set greater than 115% of the calculated current derived from:~~ ~~(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and~~ ~~(2) Reactive Power output – 150% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor~~
		~~OR~~		
		~~3c~~	~~Simulated generator bus voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing~~	~~The overcurrent element shall be set greater than 115% of the calculated current derived from:~~ ~~(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and~~ ~~(2) Reactive Power output – 100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation~~

~~A different application starts on the next page~~

~~Table 1: **Relay Loadability Evaluation Criteria**~~				
~~Application~~	**~~Relay Type~~**	**~~Option~~**	**~~Bus Voltage~~**[5]	**~~Pickup Setting Criteria~~**
~~Generator step-up transformer connected to asynchronous generators only (including inverter-based installations)~~	~~Phase distance relay (21) – directional toward the Transmission system – installed on generator-side of GSU~~ ~~If the relay is installed on the high-side of GSU use Option 10~~	~~4~~	~~Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer~~	~~The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)~~
	~~Phase time overcurrent relay (51) – installed on generator-side of GSU~~ ~~If the relay is installed on the high-side of GSU use Option 11~~	~~5~~	~~Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer for overcurrent relays installed on the low-side~~	~~The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)~~
	~~The same application continues on the next page with a different relay type~~			

~~Table 1: Relay Loadability Evaluation Criteria~~

~~Application~~	~~Relay Type~~	~~Option~~	~~Bus Voltage~~[5]	~~Pickup Setting Criteria~~
	~~Phase directional time overcurrent relay (67) – directional toward the Transmission system – installed on generator-side of GSU~~ ~~If the relay is installed on the high-side of GSU use Option 12~~	~~6~~	~~Generator bus voltage corresponding to 1.0 per unit of the high-side nominal voltage times the turns ratio of the generator step-up transformer~~	~~The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)~~
~~A different application begins below~~				
~~Generator interconnection Facilities connected to synchronous generators~~	~~Phase distance relay (21) – directional toward the Transmission system~~	~~7a~~	~~0.85 per unit of the line nominal voltage~~	~~The impedance element shall be set less than the calculated impedance derived from 115% of:~~ ~~(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and~~ ~~(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor~~
		~~OR~~		
		~~7b~~	~~Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing~~	~~The impedance element shall be set less than the calculated impedance derived from 115% of:~~ ~~(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and~~ ~~(2) Reactive Power output – 100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation~~
	~~The same application continues on the next page with a different relay type~~			

~~Table 1: Relay Loadability Evaluation Criteria~~				
~~**Application**~~	~~**Relay Type**~~	~~**Option**~~	~~**Bus Voltage**~~[5]	~~**Pickup Setting Criteria**~~
~~Generator interconnection Facilities connected to synchronous generators~~	~~Phase time overcurrent relay (51)~~	~~8a~~	~~0.85 per unit of the line nominal voltage~~	~~The overcurrent element shall be set greater than 115% of the calculated current derived from:~~ ~~(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and~~ ~~(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor~~
		~~**OR**~~		
		~~8b~~	~~Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing~~	~~The overcurrent element shall be set greater than 115% of the calculated current derived from:~~ ~~(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and~~ ~~(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation~~
	~~**The same application continues on the next page with a different relay type**~~			

~~Table 1: Relay Loadability Evaluation Criteria~~				
~~Application~~	**~~Relay Type~~**	**~~Option~~**	**~~Bus Voltage~~**[5]	**~~Pickup Setting Criteria~~**
~~Generator interconnection Facilities connected to synchronous generators~~	~~Phase directional time overcurrent relay (67) – directional toward the Transmission system~~	~~9a~~	~~0.85 per unit of the line nominal voltage~~	~~The overcurrent element shall be set greater than 115% of the calculated current derived from:~~ ~~(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and~~ ~~(2) Reactive Power output – 120% of the aggregate generation MW value, derived from the nameplate MVA rating at rated power factor~~
		~~OR~~		
		~~9b~~	~~Simulated line voltage coincident with the highest Reactive Power output achieved during field-forcing in response to a 0.85 per unit nominal voltage on the high-side terminals of the generator step-up transformer prior to field-forcing~~	~~The overcurrent element shall be set greater than 115% of the calculated current derived from:~~ ~~(1) Real Power output – 100% of the aggregate generation gross MW reported to the Transmission Planner or other entity as specified by the Regional Reliability Organization (RRO), and~~ ~~(2) Reactive Power output –100% of the aggregate generation maximum gross Mvar output during field-forcing as determined by simulation~~
~~A different application starts on the next page~~				

~~Table 1: Relay Loadability Evaluation Criteria~~				
~~Application~~	~~Relay Type~~	~~Option~~	~~Bus Voltage~~[5]	~~Pickup Setting Criteria~~
~~Generator interconnection Facilities connected to asynchronous generators only (including inverter-based installations)~~	~~Phase distance relay (21) – directional toward the Transmission system~~	~~10~~	~~1.0 per unit of the line nominal voltage~~	~~The impedance element shall be set less than the calculated impedance derived from 130% of the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)~~
	~~Phase time overcurrent relay (51)~~	~~11~~	~~1.0 per unit of the line nominal voltage~~	~~The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)~~
	~~Phase directional time overcurrent relay (67) – directional toward the Transmission system~~	~~12~~	~~1.0 per unit of the line nominal voltage~~	~~The overcurrent element shall be set greater than 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor (including the Mvar output of any static or dynamic reactive power devices)~~
~~End of Table 1~~				

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

PRC-023-3 – Transmission Relay Loadability

Project 2010-13.2 Phase II Relay Loadability

Requested Approvals

- PRC-023-3 – Transmission Relay Loadability

Requested Retirements

- PRC-023-2 – Transmission Relay Loadability

Prerequisite Approvals

- PRC-025-1 – Generator Relay Loadability*
  *A supplemental SAR was approved by the Standards Committee at their January 16-17, 2013 meeting to authorize the drafting team to make changes to PRC-023-2 to comport with the proposed draft PRC-025-1 – Generator Relay Loadability in order to establish a bright line between the applicability of load-responsive protective relays in the current transmission and the proposed generator relay loadability standards.

Revisions to Defined Terms in the NERC Glossary

- None

Background

The generator relay loadability standard drafting team and industry stakeholders raised a concern that there is no bright line to clearly distinguish which load-responsive protective relays pertain to the existing PRC-023-2 – Transmission Relay Loadability standard, effective in the United States on July 1, 2012, and the proposed PRC-025-1 – Generator Relay Loadability standard. To resolve this concern, the drafting team proposed to modify the applicability section of PRC-023-2. The standard drafting team clarified, for each functional entity, the applicability of PRC-023-2 by tying applicability to the terminal the load-responsive protective relay that it is connected to within the Transmission system.

General Considerations

It is expected that the implementation period for PRC-023-2 will have been achieved, in part, by the time PRC-023-3 is adopted by the NERC Board of Trustees and by the time of other approvals by applicable

governmental authorities. The proposed PRC-023-3 Implementation Plan now reflects specific milestone dates that are known time periods consistent with PRC-023-2.

Applicable Entities

- Distribution Provider
- Generator Owner
- Planning Coordinator
- Transmission Owner

Effective Date

New Standard

PRC-023-3	First day of the first calendar quarter 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 calendar quarter 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.

Standards for Retirement

PRC-023-2	Midnight of the day immediately prior to the Effective Date of PRC-023-3 – Transmission Relay Loadability in the particular jurisdiction in which the new standard is becoming effective, except Requirement R1, Criterion 6 which will remain in force until the effective date of PRC-025-1.

Implementation Plan for Definitions

No definitions are proposed as a part of this standard.

Implementation Plan for PRC-023-3, Requirements R1 through R6

Each Distribution Provider, Generator Owner, Planning Coordinator, and Transmission Owner applicable to this standard shall be 100% compliant on the following dates:

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1	Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above, except as noted below.	First day of the first calendar quarter, after applicable regulatory approvals	First calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
	• For supervisory elements as described in PRC-023-3 - Attachment A, Section 1.6	The later of July 1, 2014 or first day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
	• For switch-on-to-fault schemes as described in PRC-023-3 - Attachment A, Section 1.3	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1 (continued)	Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date
R2 and R3	Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R2 and R3 continued	Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date
R4	Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability	First day of the first calendar quarter six months after applicable regulatory approvals	First day of the first calendar quarter six months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R5	Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
R6	Each Planning Coordinator shall conduct an assessment by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owner, and Distribution Providers must comply with Requirements R1 through R5	Later of January 1, 2014 or the first day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Revisions or Retirements to Already Approved Standards

The following table identifies the sections of the approved standard that shall be added, retired, or revised when this standard is implemented. If the drafting team is recommending revisions, those changes are identified by the "Proposed Replacement" column.

Already Approved Standard	Proposed Replacement
PRC-023-2 4.1. Functional Entity 4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* 4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* 4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1*(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities. 4.1.4 Planning Coordinators	**PRC-023-3** 4.1.Functional Entity 4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023-2 3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* 4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* 4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023-2 3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities. 4.1.4 Planning Coordinators
Notes: The change in the proposed PRC-023-3 Applicability, Section 4.1, Functional Entity creates a bright line between those load-responsive protective relays that are applicable to PRC-023-3 – Transmission Relay Loadability and the proposed PRC-025-1 – Generator Relay Loadability. This is evident by the minor changes to the Applicability text to distinguish the applicability of the relays by which "terminal" the load-responsive protective relay is connected to within the Transmission system. Applicability is established by ownership of the load-responsive protective relays, not the Facilities.	

Already Approved Standard	Proposed Replacement
PRC-023-2 4.2. Circuits 4.2.1 Circuits Subject to Requirements R1 – R5 4.2.1.1 Transmission lines operated at 200 kV and above. 4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6. 4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6. 4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above. 4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6. 4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6. 4.2.2 Circuits Subject to Requirement R6 4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV 4.2.2.2 Transmission lines operated below 100 kV and	**PRC-023-3** 4.2. Circuits 4.2.1 Circuits Subject to Requirements R1 – R5 4.2.1.1 Transmission lines operated at 200 kV and above, except lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. 4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6. 4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6. 4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above. 4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6. 4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6. 4.2.2 Circuits Subject to Requirement R6 4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals

Already Approved Standard	Proposed Replacement
transformers with low voltage terminals connected below 100 kV that are part of the BES	connected at 100 kV to 200 kV, except lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. 4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network.
Notes: The change in the proposed PRC-023-3 Applicability, Section 4.1 Facilities, creates a bright line between those Facilities that are applicable to PRC-023-3 – Transmission Relay Loadability and those Facilities in the proposed PRC-025-1 – Generator Relay Loadability. The above applicability items for Section 4.2 "Circuits" that are subject to the standard were modified to exclude those lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The added text reads: "except lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network" and is found in Sections 4.2.1.1, 4.2.2.1, and 4.2.2.2. This eliminates an overlap with the proposed changes in PRC-025-1 and places the performance for lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network under the proposed PRC-025-1.	

<table>
<tr><th>Already Approved Standard</th><th>Proposed Replacement</th></tr>
<tr><td>PRC-023-2 (Retirement)
R1, Criterion 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.”</td><td>PRC-025-1 (New)
New Requirement
R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. [Violation Risk Factor: High] [Time Horizon: Long-Term Planning]

*Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria, Options 14 through 19. (See standard for details)</td></tr>
<tr><td colspan="2">Notes: The Transmission Owner and Distribution Provider were added to the Applicability of the proposed PRC-025-1 and excluded lines that are used exclusively to export energy directly from a Bulk Electric System (BES) generating unit or generating plant to the network; therefore, Requirement R1, Criterion 6 has been removed from the proposed standard PRC-023-3 because this criterion is now replaced (i.e., superseded) by the proposed PRC-025-1 – Generator Relay Loadability standard, Requirement R1 and its Attachment 1: Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria, Options 14 through 19. Applicability concerning generation Facilities is now addressed in the proposed PRC-025-1. Although, Requirement R1, Criterion 6 is not shown in the proposed PRC-023-3, it remains auditable while each entity assures its compliance with the proposed PRC-025-1 criteria according to the provided Implementation Plan(s).</td></tr>
<tr><td>PRC-023-2 (Retirement)
R1, Attachment A, exclusion 2.4. “Generator protection relays that are susceptible to load.”</td><td>None.</td></tr>
<tr><td colspan="2">Notes: This exclusion has been superseded by the proposed PRC-025-1 standard that pertains to these relays. The proposed PRC-023-3 standard does not include any criteria that are relevant to generator protection relays. The proposed PRC-025-1 standard establishes specific criteria for generator load-responsive protective relays, and renders this exclusion unnecessary.</td></tr>
</table>

Implementation Plan

PRC-023-3 – Transmission Relay Loadability

Project 2010-13.2 Phase II Relay Loadability

Requested Approvals

- PRC-023-3 – Transmission Relay Loadability

Requested Retirements

- PRC-023-2 – Transmission Relay Loadability

Prerequisite Approvals

- PRC-025-1 – Generator Relay Loadability*
  *A supplemental SAR was approved by the Standards Committee at their January 16-17, 2013 meeting to authorize the drafting team to make changes to PRC-023-2 to comport with the proposed draft PRC-025-1 – Generator Relay Loadability in order to establish a bright line between the applicability of load-responsive protective relays in the current transmission and the proposed generator relay loadability standards.

Revisions to Defined Terms in the NERC Glossary

- None

Background

The generator relay loadability standard drafting team and industry stakeholders raised a concern that there is no bright line to clearly distinguish which load-responsive protective relays pertain to the existing PRC-023-2 – Transmission Relay Loadability standard, effective in the United States on July 1, 2012, and the proposed PRC-025-1 – Generator Relay Loadability standard. To resolve this concern, the drafting team proposed to modify the applicability section of PRC-023-2. The standard drafting team clarified, for each functional entity, the applicability of PRC-023-2 by tying applicability to the terminal the load-responsive protective relay that it is connected to within the Transmission system.

~~Requirements R1 though R6 continue to apply to the Generator Owner to avoid a potential gap in situations where this entity owns load-responsive protective relays subject to transmission line relay loadability (PRC-023). These situations could be the result of a current configuration or future changes or additions in transmission configurations.~~

~~The proposed PRC-023-3 standard also includes two new Requirements, R7 and R8 to address load-responsive protective relay loadability in cases where the Distribution Provider or Transmission Owner owns generator interconnection Facilities or generator step-up (GSU) transformers. The implementation time for Requirements R7 and R8 comports with the periods established in the proposed PRC-025-1 Implementation Plan.~~

General Considerations

It is expected that the implementation period for PRC-023-2 will have been achieved, in part, by the time PRC-023-3 is adopted by the NERC Board of Trustees and by the time of other approvals by applicable governmental authorities. The proposed PRC-023-3 Implementation Plan now reflects specific milestone dates that are known~~,~~ time periods consistent with PRC-023-2~~, and an implementation period for new Requirements R7 and R8~~.

Applicable Entities

- Distribution Provider
- Generator Owner
- Planning Coordinator
- Transmission Owner

Effective Date

New Standard

PRC-023-3	First day of the first calendar quarter 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 calendar quarter 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.

Standards for Retirement

PRC-023-2	Midnight of the day immediately prior to the Effective Date of PRC-023-3 – Transmission Relay Loadability in the particular jurisdiction in which the new standard is becoming effective, except Requirement R1, Criterion 6 which will remain in force until the effective date of PRC-025-1.~~.~~

Implementation Plan for Definitions

No definitions are proposed as a part of this standard.

Implementation Plan for PRC-023-3, Requirements R1 through R6

Each Distribution Provider, Generator Owner, Planning Coordinator, and Transmission Owner applicable to this standard shall be 100% compliant on the following dates:

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1	Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above, except as noted below.	First day of the first calendar quarter, after applicable regulatory approvals	First calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
	• For supervisory elements as described in PRC-023-3 - Attachment A, Section 1.6	The later of July 1, 2014 or first day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
	• For switch-on-to-fault schemes as described in PRC-023-3 - Attachment A, Section 1.3	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1 (continued)	Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date
R2 and R3	Each Transmission Owner, Generator Owner, and Distribution Provider with transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R2 and R3 continued	Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date
R4	Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability	First day of the first calendar quarter six months after applicable regulatory approvals	First day of the first calendar quarter six months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R5	Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
R6	Each Planning Coordinator shall conduct an assessment by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owner, and Distribution Providers must comply with Requirements R1 through R5	Later of January 1, 2014 or the first day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

~~**Implementation Plan for PRC-023-3, Requirements R7 and R8**~~

~~**Load-responsive protective relays subject to the standard**~~

~~Each Transmission Owner and Distribution Provider that owns load-responsive protective relays applicable to this standard shall be 100% compliant on the following dates:~~

~~Requirement~~	~~Applicability~~	~~Implementation Date~~	
		~~Jurisdictions where Regulatory Approval is Required~~	~~Jurisdictions where No Regulatory Approval is Required~~
~~R7~~	~~Each Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator interconnection Facility.~~	~~Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months after applicable regulatory approvals~~	~~Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities~~
		~~Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months after applicable regulatory approvals~~	~~Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities~~

~~Requirement~~	~~Applicability~~	~~Implementation Date~~	
		~~Jurisdictions where Regulatory Approval is Required~~	~~Jurisdictions where No Regulatory Approval is Required~~
~~R8~~	~~Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator step-up transformer.~~	~~Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months after applicable regulatory approvals~~	~~Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities~~
		~~Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months after applicable regulatory approvals~~	~~Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities~~

NERC

~~**Load-responsive protective relays which become applicable to the standard**~~

~~Each Transmission Owner and Distribution Provider that owns load-responsive protective relays that become applicable to this standard, not because of the actions of the Transmission Owner and Distribution Provider including, but not limited to changes in NERC Registration Criteria, Bulk Electric System (BES) definition, or any other non-Generator Owner action, shall be 100% compliant on the following dates:~~

~~Requirement~~	~~Applicability~~	~~Implementation Date~~	
		~~Jurisdictions where Regulatory Approval is Required~~	~~Jurisdictions where No Regulatory Approval is Required~~
~~R7~~	~~Each Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator interconnection Facility.~~	~~Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months beyond the date the load-responsive protective relays become applicable to the standard~~	~~Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months beyond the date the load-responsive protective relays become applicable to the standard~~
		~~Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months beyond the date the load-responsive protective relays become applicable to the standard~~	~~Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months beyond the date the load-responsive protective relays become applicable to the standard~~

~~Requirement~~	~~Applicability~~	~~Implementation Date~~	
		~~Jurisdictions where Regulatory Approval is Required~~	~~Jurisdictions where No Regulatory Approval is Required~~
~~R8~~	~~Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator step-up transformer.~~	~~Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months beyond the date the load-responsive protective relays become applicable to the standard~~	~~Where determined by the Transmission Owner and Distribution Provider that replacement or removal is not necessary, the first day 48 months beyond the date the load-responsive protective relays become applicable to the standard~~
		~~Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months beyond the date the load-responsive protective relays become applicable to the standard~~	~~Where determined by the Transmission Owner and Distribution Provider that replacement or removal is necessary, the first day 72 months beyond the date the load-responsive protective relays become applicable to the standard~~

Revisions or Retirements to Already Approved Standards

The following table identifies the sections of the approved standard that shall be added, retired, or revised when this standard is implemented. If the drafting team is recommending revisions, those changes are identified by the "Proposed Replacement" column~~in bold blue with underlining for additions~~ ~~and for~~ ~~deletions in bold red with a strikeout~~.

Already Approved Standard	Proposed Replacement
PRC-023-2 4.1. Functional Entity 4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* 4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* 4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1*(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities. 4.1.4 Planning Coordinators	**PRC-023-3** 4.1.Functional Entity 4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023-2 3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1~~, 4.2.3, or 4.2.4~~ *(Circuits Subject to Requirements R1 – R5~~, R7, and R8~~).* 4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* 4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023-2 3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1~~, 4.2.3, or 4.2.4~~ *(Circuits Subject to Requirements R1 – R5~~, R7, and R8~~)*, provided those circuits have bi-directional flow capabilities. 4.1.4 Planning Coordinators
Notes: The change in the proposed PRC-023-3 Applicability, Section 4.1, Functional Entity creates a bright line between those load-responsive protective relays that are applicable to PRC-023-3 – Transmission Relay Loadability and the proposed PRC-025-1 – Generator Relay Loadability. This is evident by the minor changes to the Applicability text to distinguish the applicability of the relays by which "terminal" the load-responsive protective relay is connected to within the Transmission system. Applicability is established by ownership of the load-responsive protective	

Already Approved Standard	Proposed Replacement
relays, not the Facilities.	

Already Approved Standard	Proposed Replacement
PRC-023-2 4.2. Circuits 4.2.1 Circuits Subject to Requirements R1 – R5 4.2.1.1 Transmission lines operated at 200 kV and above. 4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6. 4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6. 4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above. 4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6. 4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6. 4.2.2 Circuits Subject to Requirement R6 4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV 4.2.2.2 Transmission lines operated below 100 kV and	**PRC-023-3** ~~New applicability~~ 4.2 Circuits 4.2.1 Circuits Subject to Requirements R1 – R5 4.2.1.1 Transmission lines operated at 200 kV and above, except lines that are used exclusively to export energy directly from a Bulk Electric System (BES) generating unit or generating plant to the network. 4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6. 4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6. 4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above. 4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6. 4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

Already Approved Standard	Proposed Replacement
transformers with low voltage terminals connected below 100 kV that are part of the BES ~~None.~~	4.2.2 Circuits Subject to Requirement R6 4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except lines that are used exclusively to export energy directly from a Bulk Electric System (BES) generating unit or generating plant to the network. 4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except lines that are used exclusively to export energy directly from a Bulk Electric System (BES) generating unit or generating plant to the network. 4.2.3 Circuits Subject to Requirement R7 4.2.3.1 Transmission lines that are used solely to export energy directly from a BES generating unit or generating plant to the network. 4.2.4 Circuits Subject to Requirement R8 4.2.2.2 Transformers with low voltage terminals connected below 200 kV, including generator step-up transformers, that are used solely to export energy directly from a BES generating unit or generating plant to the network.
Notes: The change in the proposed PRC-023-3 Applicability, Section 4.1 Facilities, creates a bright line between those Facilities that are applicable	

Already Approved Standard	Proposed Replacement
to PRC-023-3 – Transmission Relay Loadability and those Facilities in the proposed PRC-025-1 – Generator Relay Loadability. The above applicability items for Section 4.2 "Circuits" that are subject to the standard were modified to exclude those lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network. The added text reads: "except lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network" and is found in Sections 4.2.1.1, 4.2.2.1, and 4.2.2.2. This eliminates an overlap with the proposed changes in PRC-025-1 and places the performance for lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network under the proposed PRC-025-1.~~**Notes:** The above two new applicability items for circuits subject to the standard were added to address to situations where the Distribution Provider or Transmission Owner own either generator interconnection Facilities or generator step-up (GSU) transformers, respectively.~~	
PRC-023-2 (Retirement) R1, Criterion 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."~~.~~	**PRC-025-1 (New)~~023-3~~** **New Requirement** **R1.** Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. [Violation Risk Factor: High] [Time Horizon: Long-Term Planning] ~~R7. Each Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator interconnection Facility. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning].*~~
Notes: The Transmission Owner and Distribution Provider were added to the Applicability of the proposed PRC-025-1 and excluded lines that are used exclusively to export energy directly from a Bulk Electric System (BES) generating unit or generating plant to the network; therefore, Requirement R1, Criterion 6 has been removed from the proposed standard PRC-023-3 because this criterion is now replaced (i.e., superseded) by the proposed PRC-025-1 – Generator Relay Loadability standard, Requirement R1 and its Attachment 1: Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria, Options 14 through 19. Applicability concerning generation Facilities is now addressed in the proposed PRC-	

Already Approved Standard	Proposed Replacement
025-1. Although, Requirement R1, Criterion 6 is not shown in the proposed PRC-023-3, it remains auditable while each entity assures its compliance with the proposed PRC-025-1 criteria according to the provided Implementation Plan(s).~~**Notes:** This new requirement is included to address a gap concerning generator step-up (GSU) transformers where the Transmission Owner or Distribution Provider has applied load-responsive protective relays. Referencing the proposed Applicability section 4.2.4, Circuits Subject to Requirement R8, this requirement closes the gap for those transformers that have low voltage terminals connected below 200 kV. Currently, only those Transmission system transformers with low voltage terminals connected at 200 kV and above are applicable to the Transmission Owner or Distribution Provider or transformers with low voltage terminals under 200 kV if the Planning Coordinator determines (in accordance with requirement R6) that they should be subject to PRC-023-3. This is identified by in the proposed Applicability 4.2.1.4. This requirement eliminates the gap between the proposed PRC-023-3 and PRC-025-1 so that generator step-up (GSU) transformers (i.e., where the Transmission system transformer is the transmission line termination – Criterion 10) apply to the Transmission Owner or Distribution Provider in the proposed PRC-023-3 in the same manner as the Generator Owner in the proposed PRC-025-1.~~ ~~Circuits subject to R8 are primarily GSU transformers and also include "aggregated generator transformers" – those connecting wind farms, and photovoltaic sites.~~	
PRC-023-2 (Retirement) R1, Attachment A, exclusion 2.4. "Generator protection relays that are susceptible to load."~~None.~~	**None.** ~~**PRC-023-3**~~ ~~**New Requirement**~~ ~~R8. Transmission Owner and Distribution Provider shall set their load responsive relays in accordance with PRC-023-3, Attachment C at the terminals of the generator step-up transformer. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning].*~~
Notes: This exclusion has been superseded by the proposed PRC-025-1 standard that pertains to these relays. The proposed PRC-023-3 standard does not include any criteria that are relevant to generator protection relays. The proposed PRC-025-1 standard establishes specific criteria for generator load-responsive protective relays, and renders this exclusion unnecessary.~~**Notes:** The above new Requirement R7 addresses a gap between the proposed PRC-023-3 and PRC-025-1 standards. This requirement applies to the condition where the Transmission Owner or~~	

Already Approved Standard	Proposed Replacement
~~Distribution Provider apply load-responsive protective relays on a generator interconnection Facility(ies). Rather than add Transmission Owner and Distribution Provider to the proposed PRC-025-1, it was equally and efficient to include the same loadability criteria as the proposed PRC-025-1 in the proposed PRC-023-3 standard. Requirement R7 proposes to replace the current PRC-023-2, Requirement R1, Criterion 6 with a new requirement. Criterion 6 for setting the load-responsive protective relays so they do not operate at or below 230% now has additional flexibility in setting such relays according to Attachment C which is referenced in this new Requirement, R7. The 230% criterion comports with the loadability criteria found in the proposed PRC-023-3 Attachment C. The Transmission Owner and Distribution Provider in the proposed PRC-023-3 will have the same options for setting its load-responsive protective relays when applied on generator interconnection Facility(ies) as the Generator Owner in the proposed PRC-025-1.~~	

NERC

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Unofficial Comment Form

Project 2010-13.2 Phase II Relay Loadability
PRC-023-3

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard. The electronic comment form must be completed by **August 5, 2013**. If you have questions please contact Scott Barfield-McGinnis at Scott.Barfield@nerc.net or by telephone at (404) 446-9689.

http://www.nerc.com/pa/Stand/Pages/Project-2010-13-2-Phase-2-Relay-Loadability-Generation.aspx

Summary of changes

The generator relay loadability standard drafting team ("SDT") has revised the proposed the draft of PRC-023-3 – Transmission Relay Loadability based on stakeholder comments received during its first 30-day formal posting. The following narrative is a summary of the significant improvements made to the standard.

PRC-023-3

The SDT, based on industry stakeholder comments, made substantive changes to the PRC-023-3 standard. The chief change was removing the previously proposed Requirement R7 and R8 which applied to the generator interconnection Facility and generator step-up transformer applicable to the Distribution Provider and Transmission Owner. With this change the SDT added the Distribution Provider and Transmission Owner to the applicability of PRC-025-1 and removed the applicability of those lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network from PRC-023 to establish the bright line between standards according to stakeholder comments.

- Applicability
    - Removed references to Requirements R7 and R8
    - Added the exception to sections 4.2.1.1, 4.2.2.1, and 4.2.2.2 to exclude lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network
    - Removed the sections 4.2.3 and 4.2.4
- Requirements
    - Requirement R1, criterion 6 was removed to comport with the elimination of addressing load-responsive protective relays on lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network

- Measures
  - Removed the proposed Requirement R7
  - Removed the proposed Requirement R8
- Compliance
  - Removed R7 and R8 references
- Violation Severity Levels
  - Removed R7 and R8
- Attachment A
  - Revised criterion 2.4 as “Note Used” since it is no longer needed
- Attachment C
  - Removed due to Requirements R7 and R8 being eliminated

Implementation Plan

- Updated to reflect the transition of PRC-023-3 Requirement R1, Criterion 6 to the proposed PRC-025-1 criterion

VRF/VSL Justifications

- No change, not being provided for comment because the SDT is making substantive changes. Only references to Requirement R1, criterion 6 were removed

Please use the **electronic comment form to submit your final comments to NERC.*

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

Please note that the official comment form ***does not*** retain formatting (even if it appears to transfer formatting when you copy from the unofficial Word version of the form into the official electronic comment form). If you enter extra carriage returns, bullets, automated numbering, symbols, bolding, italics, or any other formatting, that formatting will not be retained when you submit your comments.

- Separate discrete comments by idea, e.g., preface with (1), (2), etc.
- Use brackets [] to call attention to suggested inserted or deleted text.
- Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.
- **Do not use** formatting such as extra carriage returns, bullets, automated numbering, bolding, or italics.
- **Please do not repeat other entity's comments**. Select the appropriate item to support another entity's comments. An opportunity to enter additional or exception comments will be available.

1. The drafting team has modified the Applicability in PRC-023-3 to establish a bright line between PRC-023-3 and PRC-025-1 by excluding lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network and GSU and in doing so included the DP and TO in PRC-025-1. **Do you agree that this establishes a bright line for the owners of load-responsive protective relays applied these Facilities (i.e., except lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network and GSUs)?** If not, provide specific detail that would improve the PRC-023-3 Applicability clarity or any other comment.

   ☐ Yes
   ☐ No

   Comments:

Standards Announcement

Project 2010-13.2 Phase 2 of Relay Loadability: Generation PRC-023-3 and PRC-025-1

45-Day Formal Comment Period for PRC-023-3: June 20, 2013 – August 5, 2013

Ballot Pools Forming Now: June 20, 2013 - July 19, 2013
Upcoming Initial Ballot: July 26, 2013 - August 5, 2013

30-Day Formal Comment Period for PRC-025-1: June 20, 2013 – July 19, 2013

Upcoming Successive Ballot and Non-Binding Poll: July 10, 2013 – July 19, 2013

Now Available

A 45-day formal comment period for **PRC-023-3** – Transmission Relay Loadability is now being conducted through **8 p.m. Eastern on Monday, August 5, 2013**. A ballot pool is being formed and the ballot pool window is open through **8 a.m. Eastern on Friday, July 19, 2013** *(please note that ballot pools close at 8 a.m. Eastern and mark your calendar accordingly).*

A 30-day formal comment period for **PRC-025-1** – Generator Relay Loadability is now being conducted through **8 p.m. Eastern on Friday, July 19, 2013**.

Background information for this project can be found on the project page.

Instructions for Joining Ballot Pools

A ballot pool is being formed for the standard **PRC-023-3**. Registered Ballot Body members must join the ballot pool to be eligible to vote in the balloting of PRC-023-3. Registered Ballot Body members may join the ballot pools at the following page: Join Ballot Pool

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

Initial Ballot: bp-2010-13.2_PRC-023_in@nerc.com

The ballot pool is open **through 8 a.m. Eastern on Friday, July 19, 2013**.

Instructions for Commenting

To submit comments, please use this electronic form for **PRC-023-3** and this electronic form for **PRC-025-1**. If you experience any difficulties in using the electronic form, please contact Wendy Muller . An off-line, unofficial copy of the comment forms are posted on the project page.

Next Steps

An initial ballot of **PRC-023-3** and a successive ballot of **PRC-025-1** and non-binding poll **(for PRC-025-1 only)** of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for both standards will be conducted as previously outlined.

Standards Development Process

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

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

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Standards Announcement

Project 2010-13.2 Phase 2 of Relay Loadability: Generation PRC-023-3 and PRC-025-1

45-Day Formal Comment Period for PRC-023-3: June 20, 2013 – August 5, 2013

Ballot Pools Forming Now: June 20, 2013 - July 19, 2013
Upcoming Initial Ballot: July 26, 2013 - August 5, 2013

30-Day Formal Comment Period for PRC-025-1: June 20, 2013 – July 19, 2013

Upcoming Successive Ballot and Non-Binding Poll: July 10, 2013 – July 19, 2013

Now Available

A 45-day formal comment period for **PRC-023-3** – Transmission Relay Loadability is now being conducted through **8 p.m. Eastern on Monday, August 5, 2013**. A ballot pool is being formed and the ballot pool window is open through **8 a.m. Eastern on Friday, July 19, 2013** *(please note that ballot pools close at 8 a.m. Eastern and mark your calendar accordingly).*

A 30-day formal comment period for **PRC-025-1** – Generator Relay Loadability is now being conducted through **8 p.m. Eastern on Friday, July 19, 2013**.

Background information for this project can be found on the project page.

Instructions for Joining Ballot Pools

A ballot pool is being formed for the standard **PRC-023-3**. Registered Ballot Body members must join the ballot pool to be eligible to vote in the balloting of PRC-023-3. Registered Ballot Body members may join the ballot pools at the following page: Join Ballot Pool

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

Initial Ballot: bp-2010-13.2_PRC-023_in@nerc.com

The ballot pool is open **through 8 a.m. Eastern on Friday, July 19, 2013**.

Instructions for Commenting

To submit comments, please use this electronic form for **PRC-023-3** and this electronic form for **PRC-025-1**. If you experience any difficulties in using the electronic form, please contact Wendy Muller . An off-line, unofficial copy of the comment forms are posted on the project page.

Next Steps

An initial ballot of **PRC-023-3** and a successive ballot of **PRC-025-1** and non-binding poll **(for PRC-025-1 only)** of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) for both standards will be conducted as previously outlined.

Standards Development Process

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Standards Announcement

Project 2010-13.2 Phase 2 of Relay Loadability: Generation PRC-023-3

Initial Ballot Results

Now Available

An initial ballot for **PRC-023-3** – Transmission Relay Loadability concluded at **8 p.m. Eastern on Thursday, August 8, 2013**.

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

Approval
Quorum: 80.05 % Approval: 93.00 %

Background information for this project can be found on the project page.

Next Steps

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

Standards Development Process

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

For more information or assistance, please contact Wendy Muller, Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

Ballot Results	
Ballot Name:	Project 2010-13.2 PRC-023 Ballot_1
Ballot Period:	7/26/2013 - 8/8/2013
Ballot Type:	Initial
Total # Votes:	313
Total Ballot Pool:	391
Quorum:	**80.05 % The Quorum has been reached**
Weighted Segment Vote:	93.00 %
Ballot Results:	**The Standard has Passed**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	108	1	67	0.931	5	0.069	0	7	29
2 - Segment 2	9	0.5	5	0.5	0	0	0	1	3
3 - Segment 3	86	1	62	0.939	4	0.061	0	4	16
4 - Segment 4	29	1	18	0.9	2	0.1	0	4	5
5 - Segment 5	90	1	62	0.873	9	0.127	0	8	11
6 - Segment 6	54	1	37	0.881	5	0.119	0	0	12
7 - Segment 7	1	0	0	0	0	0	0	0	1
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1
9 - Segment 9	1	0.1	1	0.1	0	0	0	0	0
10 - Segment 10	9	0.9	9	0.9	0	0	0	0	0
Totals	**391**	**6.8**	**264**	**6.324**	**25**	**0.476**	**0**	**24**	**78**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton	Affirmative	
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Big Rivers Electric Corp.	Chris Bradley		
1	Bonneville Power Administration	Donald S. Watkins	Negative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Negative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana		
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley		
1	Duke Energy Carolina	Douglas E. Hils		
1	El Paso Electric Company	Dennis Malone		
1	Entergy Transmission	Oliver A Burke	Abstain	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon		
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane		
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	Memphis Light, Gas and Water Division	Allan Long		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine		

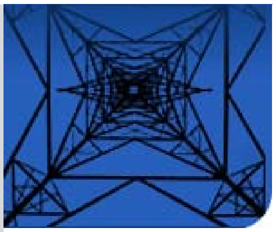
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Ryan Millard	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Abstain	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel		
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Abstain	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Abstain	
2	New Brunswick System Operator	Alden Briggs		
2	PJM Interconnection, L.L.C.	stephanie monzon		
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Affirmative	
3	Alameda Municipal Power	Douglas Draeger		
3	Ameren Services	Mark Peters	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blue Ridge Electric	James L Layton		

3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	CPS Energy	Jose Escamilla		
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala		
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	El Paso Electric Company	Tracy Van Slyke		
3	Entergy	Joel T Plessinger		
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster		
3	Georgia Power Company	Danny Lindsey	Affirmative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Affirmative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Negative	
3	Muscatine Power & Water	John S Bos		
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Rayburn Country Electric Coop., Inc.	Eddy Reece		
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	

3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Detroit Edison Company	Daniel Herring	Abstain	
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas		
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke		
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	
5	BrightSource Energy, Inc.	Chifong Thomas	Abstain	
5	Calpine Corporation	Hamid Zakery	Negative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	CPS Energy	Robert Stevens	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Detroit Edison Company	Alexander Eizans	Abstain	
5	Detroit Renewable Power	Marcus Ellis	Abstain	

5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	El Paso Electric Company	Gustavo Estrada		
5	Essential Power, LLC	Patrick Brown	Abstain	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Neil D Hammer	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	
5	Occidental Chemical	Michelle R DAntuono	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Leo Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	PacifiCorp	Bonnie Marino-Blair	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Chelan County	John Yale		
5	Public Utility District No. 1 of Lewis County	Steven Grega	Abstain	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	South Feather Power Project	Kathryn Zancanella	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Negative	
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Western Farmers Electric Coop.	Clem Cassmeyer	Negative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	

6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil		
6	El Paso Electric Company	Luis Rodriguez		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery		
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	Modesto Irrigation District	James McFall	Negative	
6	Muscatine Power & Water	John Stolley	Negative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson		
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Ty Bettis		
6	Power Generation Services, Inc.	Stephen C Knapp		
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Affirmative	
6	Tacoma Public Utilities	Michael C Hill		
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway		
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
7	Alcoa, Inc.	Thomas Gianneschi		
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein		
8		Debra R Warner	Affirmative	
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	



10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

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Consideration of Comments

Project 2010-13.2 Phase 2 Relay Loadability: Generation
PRC-023-3

The Project 2010-13.2 Phase 2 Relay Loadability: Generation standard drafting team thanks all commenters who submitted comments on PRC-023-3. This standard was posted for a 45-day public comment period from June 20, 2013 through August 8, 2013. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 27 sets of comments, including comments from approximately 90 different people from approximately 76 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

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

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

Summary of Changes

Applicability

Sections 4.2.1.1, 4.2.2.1, and 4.2.2.2 were revised to clarify the applicability by removing "except lines that are used exclusively to export energy directly from a Bulk Electric System (BES) generating unit or generating plant to the network" and replacing it with "except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads."

Implementation Plan

The phrase "load-responsive phase protection systems on" was inserted on Requirement R1, R2, and R3 Applicability of the Implementation Plan to clarify that the "Applicability" column is referring to the ownership of the relays applied on transmission lines and not the ownership of the line. Requirement R6 was clarified that it includes Parts 6.1 and 6.2.

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

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Ben Wu	Orange and Rockland Utilities	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Michael Jones	National Grid	NPCC	1
9.	David Kiguel	Hydro One Networks Inc.	NPCC	1
10.	Christina Koncz	PSEG Power LLC	NPCC	5
11.	Helen Lainis	Independent Electricity System Operator	NPCC	2
12.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
13.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
14.	Bruce Metruck	New York Power Authority	NPCC	6
15.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
16.	Lee Pedowicz	NPCC	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1

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

18. Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19. David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
20. Brian Robinson	Utility Services	NPCC	8
21. Brian Shanahan	National Grid	NPCC	1
22. Wayne Sipperly	New York Power Authority	NPCC	5
23. Donald Weaver	New Brunswick System Operator	NPCC	2

				1	2	3	4	5	6	7	8	9	10
2.	Group	Jason Marshall	ACES Standards Collaborators						X				

Additional Member	Additional Organization	Region	Segment Selection
1. David Sofra	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
2. John Shaver	Arizona Electric Power Cooperative	WECC	4, 5
3. John Shaver	Southwest Transmission Cooperative	WECC	1
4. Mark Ringhausen	Old Dominion Electric Cooperative	SERC	3, 4
5. Michael Brytowski	Great River Energy	MRO	1, 3, 5, 6
6. Shari Heino	Brazos Electric Power Cooperative	ERCOT	1, 5
7. Mohan Sachdeva	Buckeye Power	RFC	3, 4

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

Additional Member	Additional Organization	Region	Segment Selection
1. John Allen	City Utilities of Springfield	SPP	1, 4
2. Andy Evans	Westar Energy	SPP	1, 3, 5, 6
3. Louis Guidry	Cleco Power LLC	SPP	1, 3, 5
4. Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
5. Bo Jones	Westar Energy	SPP	1, 3, 5, 6
6. Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
7. James Nail	City of Independence Power & Light Department	SPP	3
8. Lynn Schroeder	Westar Energy	SPP	1, 3, 5, 6
9. Kevin Stephan	Westar Energy	SPP	1, 3, 5, 6

				1	2	3	4	5	6	7	8	9	10
4.	Group	David Thorne	Pepco Holdings Inc & Affiliates	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. Carl Kinsley	Delmarva Power & Light Co	RFC	1, 3
2. Alvin Depew	Pepco Holdings Inc	RFC	1, 3

				1	2	3	4	5	6	7	8	9	10
5.	Group	Wayne Johnson	Southern Company: Southern Company Services, Inc., Alabama Power Company, Georgia Power Company, Gulf Power	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
			Company, Mississippi Power Company, Southern Company Generation, Southern Company Generation and Energy Marketing										

No additional members listed.

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	David Greene	SERC Protection and Controls Subcommittee										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Nauert	Ameren		
2.	Steve Edwards	Dominion Virginia Power		
3.	Phil Winston	Southern Company Services		
4.	David Greene	SERC RRO		

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Russel Mountjoy	MRO NERC Standards Review Forum (NSRF)	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
2.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
3.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
4.	Keyleigh Wilkerson	Lincoln Electric Systems	MRO	1, 3, 5, 6
5.	Jodi Jensen	Western Area Power Admininstration	MRO	1, 6
6.	Joseph DePoorter	Madison Gas and Electric	MRO	3, 4, 5, 6
7.	Ken Goldsmith	Alliant Energy	MRO	4
8.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
9.	Marie Knox	Midcontinent Independent System Operator	MRO	2
10.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
11.	Scott Bos	Muscatine Power and Water	MRO	1, 3, 5, 6
12.	Scott Nickels	Rochester Public Utilities	MRO	4
13.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
14.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
15.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	DeWayne Scott		SERC	1
2.	Ian Grant		SERC	3
3.	David Thompson		SERC	5

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

	Additional Member	Additional Organization	Region	Segment Selection
4.	Marjorie Parsons		SERC	6
5.	Daniel McNeely		SERC	1

				1	2	3	4	5	6	7	8	9	10
9.	Group	Louis Slade	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jeff Bailey	Nuclear		5
2.	Michael Crowley	Eletcric Transmission	SERC	1, 3
3.	Chip Humphrey	Power Generation	SERC	5
4.	Sean Iseminger	Power Generation	RFC	5
5.	Matt Woodzell	Power Generation	NPCC	5
6.	Mike Garton	NERC Compliance Policy	NPCC	5, 6
7.	Connie Lowe	NERC Compliance Policy	SERC	1, 3, 5, 6
8.	Randi Heise	NERC Compliance Policy	RFC	5, 6

				1	2	3	4	5	6	7	8	9	10
10.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
11.	Individual	Thomas Foltz\	American Electric Power	X		X		X	X				
12.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
13.	Individual	Don Weaver	New Brunswick System Operator		X								
14.	Individual	Michelle D'Antuono	Occidental Energy Ventures Corp					X					
15.	Individual	Michael Falvo	Independent Electricity System Operator		X								
16.	Individual	David Jendras	Ameren	X		X		X	X				
17.	Individual	Travis Metcalfe	Tacoma Power	X		X	X	X	X				
18.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
19.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
20.	Individual	Shaun Moran	NIPSCO	X		X		X	X				
21.	Individual	Jonathan Meyer	Idaho Power Co.	X									
22.	Individual	Bill Fowler	City of Tallahassee			X							
23.	Individual	Michael Lowman	Duke Energy	X		X		X	X				
24.	Individual	Bradley Collard	Oncor Electric Delivery Company LLC	X									
25.	Individual	Spencer Tacke	Modesto Irrigation District			X	X		X				
26.	Individual	Ed O'Brien	Modesto Irrigation District			X	X	X					
27.	Individual	Melissa Kurtz	US Army Corps of Engineers					X					

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

Summary Consideration:

The SERC PCS comments suggested leaving PRC-023-2, Criterion 2.4 in the version three revision. The drafting team noted that Criterion 2.4 is no longer necessary due to the revised Applicability. These relays are now applicable to the NERC Board of Trustees adopted PRC-025-1 standard.

Organization	Agree	Supporting Comments of "Entity Name"
Ameren	Agree	We agree with and support SERC PCS comments for PRC-023-3.

1. **The drafting team has modified the Applicability in PRC-023-3 to establish a bright line between PRC-023-3 and PRC-025-1 by excluding lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network and GSU and in doing so included the DP and TO in PRC-025-1. Do you agree that this establishes a bright line for the owners of load-responsive protective relays applied these Facilities (i.e., except lines that are used exclusively to export energy directly from a BES generating unit or generating plant to the network and GSUs)? If not, provide specific detail that would improve the PRC-023-3 Applicability clarity or any other comment.**

Summary Consideration:

All of the drafting team's modifications to the proposed PRC-023-3 standard were non-substantive. Stakeholder majority comments were limited to the Applicability section changes regarding how the drafting team implemented the phrase "except lines that are used exclusively to export energy directly from a Bulk Electric System (BES) generating unit or generating plant to the network" rather than "generator interconnection facilities." Applicability comments were provided by approximately four entities and supported by as many as 31 individuals. The drafting team remains steadfast in that the phrase "generator interconnection facilities" does not provide the needed clarity for the facilities applicable to the standard; however, based on other similar comments, the drafting team provided a non-substantive change to the three occurrences of the phrase "except lines that are used exclusively to export energy directly from a Bulk Electric System (BES) generating unit or generating plant to the network" by replacing it with "except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads." This clarification also clarifies a minority comment about how the original proposed language addressed conditions where those same interconnection lines also provided station service or even cases where the generating plant was a pumped storage facility.

One comment supported by approximately 24 individuals requested clarification on in the implementation plan to clarify the applicability is not the transmission line, but the ownership of the load-responsive protective relays. The drafting team made the clarifying revision to the suggested Requirement R1 and also in Requirements R2 and R3 of the Implementation Plan.

The remaining comments were all minority concerns that did not result in a revision to the standard. Approximately three comments supported by 18 individuals suggested changes to Requirement R2 of the proposed draft PRC-023-3 standard concerning out-of-step blocking. The drafting team appreciates comments that improve the standard; however, this offered suggestion was outside the scope of the drafting team's effort to establish a bright line between the existing PRC-023-2 and the new PRC-025-1. There were a few of comments regarding the PRC-023 standard's criterion. For example, there was one comment representing about 8 individuals suggesting to leave Requirement R1, Criterion 6 and Item 2.4 in Attachment A in the proposed PRC-023-3 standard. The drafting team disagreed that these were no longer relevant to the standard as the criterion is now applicable to the NERC Board of Trustees adopted PRC-025-1 – Generator Relay Loadability standard. The same comment also suggested removing Requirement R1, Criterion 7; however, the drafting team disagreed because this criterion may be useful. One other comment represented by five individuals supported the removal of 2.4 in Attachment A.

An additional minority comment supported by three individuals included a concern about the regulatory approval timeline of both the proposed PRC-023-3 and the NERC Board of Trustees adopted PRC-025-1. The implementation plan of each standard, requires that they both be approved by the regulatory authority together to avoid a reliability gap and compliance overlap. Two individuals commented that the standard should only apply to generators and transformers that are material to the Bulk Electric System. The drafting team noted that Elements such as generators or transformers that are demonstrated to be material to the BES will likely be declared to be BES Elements under the provisions of the BES exception process. Other minority comments were editorial in nature by single individuals and include capitalizing “system operator” in the Purpose of the standard, using a word other than “export” (i.e., “export energy”), adding “Requirement” inside the parenthetical numbered requirement at the end of each Measure, and an observation about the posted redline to the previous posting of the standard being inaccurate. The drafting team did not make any revisions based on these comments including not correcting the previously posted document.

Organization	Yes or No	Question 1 Comment
ACES Standards Collaborators	No	(1) The proposed changes are closer to establishing a bright line but still do not go far enough. (2) For consistency with Project 2010-07 Generator Requirements at the Transmission Interface, we request using “generator interconnection Facility” rather than “lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network”. While we understand the purpose of using the latter term is avoid the implication that “generator interconnection Facility” is owned by the Generator Owner, the latter term actually creates more confusion and will likely lead to inconsistent enforcement. Furthermore, based on the Guidelines and Technical Basis for PRC-025, the rationale for using the term is only applicable to PRC-025 and not PRC-023. PRC-023 is already applicable to the Distribution Provider so there is no need to expand applicability.

Organization	Yes or No	Question 1 Comment
		Response: The drafting team made changes to PRC-025-1 during this comment period to address these concerns. The drafting team made non-substantive changes to the PRC-023-3 Applicability 4.2.1.1, 4.2.2.1, and 4.2.2.2 to clarify the facility applicability. Change made. The concern raised about the Distribution Provider's applicability in PRC-025-1 was addressed in the PRC-025-1 response to comments. No change made. (3) Since the "generator interconnection Facility" term has already been established in other standards and was deemed to be understood well enough by industry that the Project 2010-07 Generator Requirements at the Transmission Interface drafting team decided a glossary term was not necessary contrary to the ad hoc report, the same terminology should be used in PRC-023 to avoid confusion and inconsistency. Confusion could arise with enforcement and compliance personnel over the use of the term "lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network" and how to apply the standard to the GO. This will result in the GO, NERC and Regional Entities expending resources on unnecessary compliance activities that do not support reliability. **Response:** The drafting team notes that previous stakeholder comments revealed that the phrase "generator interconnection facility" was unclear and led the team to revising the applicability not to use the phrase. No change made. (4) For PRC-023, we further request that the "generator interconnection Facility" term be further refined to "non-radial generator interconnection Facility" or "networked generator interconnection Facility". From the Guideline and Technical Basis document for PRC-025, we understand that PRC-023 is applicable to the GO because some "generation interconnection Facilities" are networked as shown in Figure 3 of the document. Figure 3 depicts a common situation in which a generator that was looped into an

Organization	Yes or No	Question 1 Comment
		existing line such that current can flow from the grid through the high side bus of the generator step up transformer back to the grid. This additional refinement is needed to clarify in what limited situations PRC-023 would be applicable to the Generator Owner. (5) We request that applicability section 4.1.2 be modified to clarify it is only applicable to Generator Owners that own networked or non-radial "lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network" or "generator interconnection Facilities". **Response (Items 4 & 5):** The drafting team made non-substantive changes to the PRC-023-3 Applicability 4.2.1.1, 4.2.2.1, and 4.2.2.2 to clarify the facility applicability. Change made. (6) We understand that the term "lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network" was used in PRC-023 because the Guidelines and Technical Basis document indicated there was a concern that a Distribution Provider may own a "generation interconnection Facility" and that the term implies ownership by the GO. We disagree with this implication and we have found numerous references including the November 16, 2009 Final Report from the Ad Hoc Group for Generator Requirements at the Transmission Interface that indicate the facility may or may not be owned by the GO. Furthermore, the original proposed definition of a "generation interconnection Facility" from the report did not indicate ownership. **Response:** The drafting team notes that previous stakeholder comments revealed that the phrase "generator interconnection facility" was unclear and led the team to revising the applicability not to use the phrase. No change made. (7) While we understand the intended use of the term "except lines and

Organization	Yes or No	Question 1 Comment
		transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network" was used in PRC-025 because of the drafting team's concern of the implication of GO ownership would prevent applicability to the DP, we find it is unnecessary in PRC-023. PRC-023 is already otherwise applicable to PRC-023 because a DP might own Transmission Protection Systems as identified in the NERC compliance registry. If the DP did own networked "generation interconnection Facility" above the 100 kV threshold compliance registry criteria, they would be registered as a Transmission Owner as well. Furthermore, PRC-023 R6 would still allow the PC to identify networked facilities below 100 kV that the DP owns. **Response:** The Distribution Provider is included to address those cases where a Distribution Provider owns load-responsive protective relays on the Elements listed in the Applicability section of the standard. This also avoids an entity having to register as a Transmission Owner for this specific condition. No change made. (8) There are inconsistencies between the terms in PRC-023 and PRC-025 that are intended to apply to non-radial and radial generator interconnection Facilities. PRC-025 uses the term "Elements that connect a GSU transformer to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant" while PRC-023 uses slight variants of the term "except lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network". Some differences that should be eliminated include the appended "to the network" in the PRC-023 term, use of "Elements" in PRC-025, and use of "lines and transformers". **Response:** The drafting team made non-substantive changes to the PRC-023-3 Applicability 4.2.1.1, 4.2.2.1, and 4.2.2.2 to eliminate the noted inconsistencies. Change made.

Organization	Yes or No	Question 1 Comment
Response: The drafting team thanks you for your comments; please see the above responses.		
NIPSCO	No	Summary of added clarification: this entity suggests that clarification of requirements is needed for Requirement 2 (R2) with regards to "out-of-step blocking" since this "out of step blocking" function may or may not be implemented on every BES facilties' protection scheme and should be held under the judgment of the protection and control engineer. Some may read the existing standard requirement R2 wording as “an explicit requirement to indeed set "out of step blocking" elements on all protective relays equipped with the element as an option, set in the manner described in R2”. This is assumed not to be the intention by the wording of the standard. We suggest the following: ***R2.*** *Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements[, if implemented,]to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]*
Response: The drafting team thanks you for your comments and notes this suggestion is out of scope of the project. No change made.		
Modesto Irrigation District	No	I am voting NO on this revision to this NERC Standard, because I would suggest the following changes be made: 1. Section 4.2.1.3 (under "Circuits Subject to Requirements R1 - R5") needs be revised to read "Transmission lines operated below 100 kV that have been shown to have a material impact to the reliability of the adjacent interconnected system, or as selected by the Planning Authority in accordance with Requirement R6".

Organization	Yes or No	Question 1 Comment
		2. Section 4.2.1.6 (under "Circuits Subject to Requirements R1 - R5") needs be revised to read "Transformers with low voltage terminals connected below 100 kV that have been shown to have a material impact to the reliability of the adjacent interconnected system, or as selected by the Planning Authority in accordance with Requirement R6". Thank you.
Response: The drafting team thanks you for your comments and notes that Elements such as generators or transformers that are demonstrated to be material to the BES will likely be declared to be BES Elements under the provisions of the BES exception process; therefore, will be made applicable to the standard. No change made.		
Modesto Irrigation District	No	1. Section 4.2.1.3 (under "Circuits Subject to Requirements R1 - R5") needs be revised to read "Transmission lines operated below 100 kV that have been shown to have a material impact to the reliability of the adjacent interconnected system, or as selected by the Planning Authority in accordance with Requirement R6". 2. Section 4.2.1.6 (under "Circuits Subject to Requirements R1 - R5") needs be revised to read "Transformers with low voltage terminals connected below 100 kV that have been shown to have a material impact to the reliability of the adjacent interconnected system, or as selected by the Planning Authority in accordance with Requirement R6".
Response: The drafting team thanks you for your comments and notes that Elements such as generators or transformers that are demonstrated to be material to the BES will likely be declared to be BES Elements under the provisions of the BES exception process; therefore, will be made applicable to the standard. No change made.		
Northeast Power Coordinating Council	Yes	Other comments: Most, if not all of the lines being excluded from the Standard could still be utilized to provide station service supply to the generating plant. Are any lines used “exclusively” to export energy from a BES GO? Would lines used to supply station service load at generating plants (for example during

Organization	Yes or No	Question 1 Comment
		generator shutdown) still be excluded from PRC-023-3? **Response:** The drafting team made non-substantive changes to the PRC-023-3 Applicability 4.2.1.1, 4.2.2.1, and 4.2.2.2 to clarify the facility applicability. Change made. From the Applicability for R1 on page 3 of the Implementation Plan for PRC-023-3 should be revised from “Each Transmission Owner, Generator Owner and Distribution Provider with transmission lines operating at...” to “Each Transmission Owner, Generator Owner and Distribution Provider with load-responsive protection systems on transmission lines operating at...” The transmission line owner and load-responsive relay owner could be represented by two or more different entities. The owner of the load-responsive protection system should be responsible for compliance as identified properly under Section 4, Applicability of PRC-023-3. The Implementation Plan should not contradict Applicability or the Requirements set forth in the Standard. **Response:** The drafting team made the suggested non-substantive edits to clarify the implementation plan that applicability is based on the ownership of the relays. Change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Pepco Holdings Inc & Affiliates	Yes	We agree with all the proposed changes to PRC-023-3. However, we have concerns with the proposed implementation plan for PRC-023-3 and the proposed retirement date of PRC-023-2. The entire PRC-023-2 standard should remain in force until the effective date of PRC-025-1, not just Requirement R1, Criterion 6. This is because PRC-023-2 also includes generator protection relays that are susceptible to load (PRC-023-2 Attachment A, Section 2.4). If PRC-023-2 is retired and PRC-023-3 becomes effective prior to the full implementation of PRC-025-1 there could be a gap

Organization	Yes or No	Question 1 Comment
		in compliance associated with generator protection relays previously subject to PRC-023-2. As such, we believe the implementation of PRC-025-1 and PRC-023-3 as well as the retirement of PRC-023-2 should all be coincident.
Response: The drafting team thanks you for your comment and notes that the Implementation Plan for both PRC-023-3 and PRC-025-1 dictate that both need to be approved simultaneously by regulators to avoid the described gap. No change made.		
Southern Company: Southern Company Services, Inc., Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, Southern Company Generation, Southern Company Generation and Energy Marketing	Yes	1) We endorse the SERC Protection & Control Subcommittee (PCS) comment: Please include, rather than remove, 2.4 in Attachment A (“Protective relays applied at the terminals of generation Facilities...”) because this reinforces the bright line between PRC-023-3 and PRC-025-1; **Response:** The drafting team contends that Criterion 2.4 is no longer necessary due to the revised Applicability. These relays are now applicable to the NERC Board of Trustees adopted PRC-025-1 standard. No change made. 2) We have an observation regarding terminology between terms used in PRC-023-3 and PRC-025-1: The Transmission standard discusses 'electrical network' and 'the network' in the Purpose and Applicability (See Part A. 4.2.1.1, 4.2.2.1, and 4.2.2.2) while the Generator standard discusses 'Transmission system' at the Applicability section 3.2.4. Should these terms all be the same? **Response:** The drafting team made non-substantive changes to the PRC-023-3 Applicability 4.2.1.1, 4.2.2.1, and 4.2.2.2 to eliminate the noted inconsistencies. Change made. 3) We feel that all the transmission line terminal setting criteria should have remained in PRC-023. **Response:** The drafting team notes that Criterion 6 was removed (i.e., “Not used”) because it is no longer applicable to the standard based on the changes made to align PRC-023-3 with PRC-025-1. No change made.

Organization	Yes or No	Question 1 Comment
Response: The drafting team thanks you for your comments; please see the above responses.		
SERC Protection and Controls Subcommittee	Yes	Please include, rather than remove, 2.4 in Attachment A (“Protective relays applied at the terminals of generation Facilities...”) because this reinforces the bright line between PRC-023-3 and PRC-025-1. The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Response: The drafting team thanks you for your comment and contends that Criterion 2.4 is no longer necessary due to the revised Applicability. These relays are now applicable to the NERC Board of Trustees adopted PRC-025-1 standard. No change made.		
MRO NERC Standards Review Forum (NSRF)	Yes	The NSRF agrees that this revision of PRC-023-3 establishes a bright line for load-responsive relay owners between generating units and transmission networks. The following is an additional comment regarding PRC-023-3 content: The requirements in R2 with regard to out-of-step blocking are not supported in the technical reference document. Out-of-step relaying does not seem to fall under the purpose of the PRC-023-3 as it is suggested they do not “limit transmission loadability.” For these reasons requirement R2 should be deleted.
Response: The drafting team thanks you for your comment and notes this suggestion is out of scope of the project. No change made.		
Manitoba Hydro	Yes	Although Manitoba Hydro is in general agreement with the standard, we have the following comments (1) Purpose - for clarity, consider replacing the words “system operators’”

Organization	Yes or No	Question 1 Comment
		with [a System Operator(s)"]. **Response:** The drafting team that originally developed the PRC-023 standard intended the term "system operators" to be used in the more general use rather than the more definite NERC Glossary term. No change made. (2) Measures (M1-M6) - for consistency with the Data Retention section, consider adding the word [Requirement] before the bracketed requirements - R1, R2, R3, R4, R5 and R6 found at the end of each of the measures. **Response:** The drafting team considered the suggestion and elected not to make the editorial suggestion in the Measures where each requirement is linked parenthetically to an actual Requirement. Such changes would not be consistent with the body of standards that use this convention. No change made. (3) PRC 023-3, Sections 4.2.1.1 and 4.2.2.1 - have been revised to exclude lines and transformers that are used exclusively to "export" energy directly from a Bulk Electric System (BES) generating unit to the network. Use of the term "export" implies that the energy is delivered from one government jurisdiction to a foreign jurisdiction. It is not clear why such a term would be used. Unless this was the actual intention, the term "export" should be replaced with [transmit] or [deliver]. **Response:** The drafting team made non-substantive changes to the PRC-023-3 Applicability 4.2.1.1, 4.2.2.1, and 4.2.2.2 to clarify the facility applicability. Change made. The drafting team notes that the understanding of the term "export energy" may be slightly different. The term "export energy" is synonymous with "deliver" or "transmit." No change made. (4) Implementation Plan - In the Implementation Plan chart for R6, the "Applicability" section does not describe the applicable entities for the requirement. Instead, it describes part of the requirement. The Applicable

Organization	Yes or No	Question 1 Comment
		entities should be identified. Also, as drafted only one part of the requirement is addressed by the Implementation Plan chart. If the intent is to create 2 different effective dates for different parts of R6, this should be specified in the first column. **Response:** The drafting team notes that the only update to the Implementation Plan was to include the known dates as a reference for industry. Additionally, the drafting team had no specific reason to address changes in the language of the plan because the performance of the requirements was not changing with regard to transmission relays. The drafting team recognizes after reviewing the comment above that the R6 "Applicability" text in the Implementation Plan reads more like the actual Requirement R6 language; whereas, the Applicability text for requirements R1-R5 are more generic and relates to the entities and circuits identified in the PRC-023-3 Applicability section. Since the Implementation Plan is materially the same as the plan approved with version two of the PRC-023-3 standard and that the drafting team has not received earlier concern about the language, the drafting team decided not to revise the text. The drafting team does offer that the style and manner the Implementation Plan is written, the time periods associated with R6 do include its sub-parts 6.1 and 6.2. No change made.
Response: The drafting team thanks you for your comments; please see the above responses.		
Occidental Energy Ventures Corp	Yes	Occidental Energy Ventures Corp. believes that the project team has taken a far more elegant approach in separating relays designed to protect transmission equipment from those protecting generation equipment - without regard to the relay owner. The previous method required criteria duplicated from PRC-025-1, which was difficult to follow. With multiple other generator protection system standards pending -

Organization	Yes or No	Question 1 Comment
		including Phase III development of Project 2010-13 - we would like to see a regulatory commitment to a comprehensive risk-based Compliance approach to the topic. We share NERC's concern that Misoperations continue to be a leading cause of BES events; due in major part to the complex interaction of Protection System schema. In this model, the settings criteria in all PRC standards must be continually evaluated against event data - which NERC is just beginning to accumulate. This means that those standards which do not show progress in reducing BES risk, must be aggressively withdrawn in favor of those which do. Only then can we be comfortable that the most effective critieria is in place.
Response: Thank you for your comment. Monitoring, analyzing, and tracking trends in Protection System Misoperations are critical to improving BES reliability. Misoperation data collection provides several benefits to BES reliability and supports NERC's mission of ensuring the reliability of the BPS. NERC is committed to working with stakeholders to provide high value risk analysis with the goal of identifying areas for improvement in Misoperation rates and supporting comprehensive solutions. NERC is obligated to conduct five-year reviews of standards that are more than five years old and have not yet been revised through other standards development projects. Within the next year, all standards that have not been significantly revised or retired will undergo a comprehensive review to determine whether the standard should be reaffirmed, revised, or withdrawn. NERC has responded to regulatory and industry guidance by incorporating into its five-year review process principles of results-based standards drafting and a review of each standard in relation to other standards to eliminate duplicative requirements. Additionally, five-year reviews will evaluate whether each standard is clear, concise, and technically sound given current technologies and system conditions, whether any regulatory directives require specific changes to the standard, and whether the requirements that do little to ensure the reliability of the BPS should be eliminated. Five-year reviews also will consider previously captured stakeholder-identified issues pertaining to the affected standards. No change made.		
Tacoma Power	Yes	On page 14 of the redlined Implementation Plan for PRC-023-3, 4.2.3 and 4.2.4 in Proposed Replacement column should be deleted.
Response: The drafting team thanks you for identifying this error. A manual redline, rather than an automatic one, was created for clarity. Automatic redlining does not always yield the best mark-up and therefore makes understanding the changes difficult; while manual redlining tends to introduce errors in attempting to make the changes more apparent. No change made will be made to the		

Organization	Yes or No	Question 1 Comment
previously posted redline. The clean version that was posted contemporaneously with the redline version was correct. No change made.		
Xcel Energy	Yes	Xcel Energy believes Requirement 1, Criteria 7 should be removed from the standard. It does not have an application with the addition ‘except lines that are used exclusively to export energy directly from a Bulk Electric System (BES) generating unit or generating plant to the network’ to Applicability 4.2.1.1.
Response: The drafting team thanks you for your comment and contends that Criterion 7 may still be useful. No change made.		
Kansas City Power & Light	Yes	In the Implementation Plan, page 14, 4.2.3 and 4.2.4 are shown in the proposed replacement column. 4.2.3 and 4.2.4 refer to Requirements R7 and R8 which have been removed. The text is not included in the already approved standard and is not red-lined in the proposed replacement column, so I imagine that this was pasted in accidentally.
Response: The drafting team thanks you for identifying this error. A manual redline, rather than an automatic one, was created for clarity. Automatic redlining does not always yield the best mark-up and therefore makes understanding the changes difficult; while manual redlining tends to introduce errors in attempting to make the changes more apparent. No change made will be made to the previously posted redline. The clean version that was posted contemporaneously with the redline document was correct. No change made.		
Duke Energy	Yes	Duke Energy agrees that the modifications implemented by the drafting team creates the necessary bright line between PRC-023-1 and PRC-025-1.
Response: The drafting team thanks you for your comment.		
Oncor Electric Delivery Company LLC	Yes	The word “exclusively” should be changed to “primarily” as these interconnect lines are also used to import power during non-generation periods.

Organization	Yes or No	Question 1 Comment
Response: The drafting team thanks you for your comment and notes it made non-substantive changes to the PRC-023-3 Applicability 4.2.1.1, 4.2.2.1, and 4.2.2.2 to clarify the facility applicability. Change made.		
US Army Corps of Engineers	Yes	The requirements in R2 with regard to out-of-step blocking are not supported in the technical reference document. Out-of-step relaying does not seem to fall under the purpose of the PRC-023-3 as it is suggested they do not "limit transmission loadability." For these reasons requirement R2 should be deleted.
Response: The drafting team thanks you for your comment and notes this suggestion is out of scope of the project. No change made.		
Tennessee Valley Authority	Yes	
Dominion	Yes	
Arizona Public Service Company	Yes	
American Electric Power	Yes	
New Brunswick System Operator	Yes	
Independent Electricity System Operator	Yes	
Idaho Power Co.	Yes	
City of Tallahassee	Yes	
SPP Standards Review Group	Yes	
Ameren		

END OF REPORT

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. The Standards Committee approved the Supplemental SAR regarding PRC-023-2 for posting on January 16-17, 2013.
2. The Supplemental SAR was posted for a 45-day informal comment period from January 25, 2013 to March 11, 2013 along with a red-lined Draft 1 of the revised standard.
3. Draft 2 of the revised standard was posted for a 30-day formal comment period from April 25, 2013 to May 24, 2013.
4. Draft 3 of the revised standard was posted for a 45-day formal comment period from June 20, 2013 to August 8, 2013 and an initial ballot in the last 10 days of the comment period.

Description of Current Draft

The Generator Relay Loadability Standard Drafting Team (GENRLOSDT) is posting Draft 4 of PRC-023-3 – Transmission Relay Loadability for a 10-day recirculation ballot.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	April 2013
45-day Formal Comment Period and Initial Ballot	June 2013
10-day Recirculation Ballot	August 2013
BOT adoption	November 2013
File with FERC	December 2013

Effective Dates

See PRC-023-3 Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New

Version	Date	Action	Change Tracking
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — “then” should be “than.”	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	TBD	Clarify applicability for consistency with PRC-025-1 and other minor corrections	Supplemental SAR (Project 2010-13.2)

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.

No new or revised term is being proposed.

A. Introduction

1. **Title:** **Transmission Relay Loadability**
2. **Number:** PRC-023-3
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. Functional Entity:

4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinator

4.2. Circuits:

4.2.1 Circuits Subject to Requirements R1 – R5:

4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

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

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6:

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. **Effective Dates:** See Implementation Plan.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. 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] [Time Horizon: Long Term Planning]*.

Criteria:

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).
2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).
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:
   - An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
   - 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.
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 Requirement R1, criterion 3, using the full line inductive reactance.
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).
6. Not used.

[1] 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.

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.

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.

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.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays 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.

10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 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, for at least 15 minutes to provide time 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 set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

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:

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

b. 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.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

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[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

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. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 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]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-3 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-3, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

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

The Compliance Enforcement Authority shall keep the last audit record 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.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated.	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met

Requirement	Lower	Moderate	High	Severe
		(part 6.2)		6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. 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, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

PRC-023-3 — 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).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

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

2.1. 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 except as noted in section 1.6.

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

2.4. Not used.

2.5. Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-3 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

   i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

   ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

   iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

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. The Standards Committee approved the Supplemental SAR regarding PRC-023-2 for posting on January 16-17, 2013.
2. The Supplemental SAR was posted for a 45-day informal comment period from January 25, 2013 to March 11, 2013 along with a red-lined Draft 1 of the revised standard.
3. Draft 2 of the revised standard was posted for a 30-day formal comment period from April 25, 2013 to May 24, 2013.
4. Draft 3 of the revised standard was posted for a 45-day formal comment period from June 20, 2013 to August 8, 2013 and an initial ballot in the last 10 days of the comment period.

Description of Current Draft

The Generator Relay Loadability Standard Drafting Team (GENRLOSDT) is posting Draft ~~3~~4 of PRC-023-3 – Transmission Relay Loadability for a ~~45~~10-day ~~formal comment period and initial~~recirculation ballot.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	April 2013
45-day Formal Comment Period and Initial Ballot	June 2013
10-day Recirculation Ballot	August 2013
BOT adoption	November 2013
File with FERC	December 2013

Effective Dates

See PRC-023-3 Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New

Version	Date	Action	Change Tracking
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	TBD	Clarify applicability for consistency with PRC-025-1 and other minor corrections	Supplemental SAR (Project 2010-13.2)

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.

No new or revised term is being proposed.

A. Introduction

1. **Title:** **Transmission Relay Loadability**

2. **Number:** PRC-023-3

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. Functional Entity:

4.1.1 Transmission Owner with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.2 Generator Owner with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution Provider with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinator

4.2. Circuits:

4.2.1 Circuits Subject to Requirements R1 – R5:

4.2.1.1 Transmission lines operated at 200 kV and above, except ~~lines~~Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a ~~Bulk Electric System (~~BES~~)~~ generating unit or generating plant~~ to the network~~. Elements may also supply generating plant loads.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

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

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6:

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except ~~lines and transformers~~Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~to the network~~. Elements may also supply generating plant loads.

4.2.2.2 Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except ~~lines and transformers~~Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~to the network~~. Elements may also supply generating plant loads.

5. **Effective Dates:** See Implementation Plan.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. 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] [Time Horizon: Long Term Planning]*.

Criteria:

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).

2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).

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

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 Requirement R1, criterion 3, using the full line inductive reactance.

[1] 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.

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).

6. Not used.

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.

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.

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.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays 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.

10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 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, for at least 15 minutes to provide time 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 set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

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:

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

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[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

b. 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.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

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. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion 7, 8, 9, 12, or 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]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-3 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-3, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Data Retention

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

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

The Compliance Enforcement Authority shall keep the last audit record 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.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated.	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met

Requirement	Lower	Moderate	High	Severe
		(part 6.2)		6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. 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, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

PRC-023-3 — 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).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

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

2.1. 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 except as noted in section 1.6.

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

2.4. Not used.

2.5. Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-3 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is a monitored Facility of an Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

   i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

   ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

   iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

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. The Standards Committee approved the Supplemental SAR regarding PRC-023-2 for posting on January 16-17, 2013.
2. The Supplemental SAR was posted for a 45-day informal comment period from January 25, 2013 to March 11, 2013 along with a red-lined Draft 1 of the revised standard.
3. Draft 2 of the revised standard was posted for a 30-day formal comment period from April 25, 2013 to May 24, 2013.
4. Draft 3 of the revised standard was posted for a 45-day formal comment period from June 20, 2013 to August 8, 2013 and an initial ballot in the last 10 days of the comment period.

Description of Current Draft

The Generator Relay Loadability Standard Drafting Team (GENRLOSDT) is posting Draft 4 of PRC-023-3 – Transmission Relay Loadability for a 10-day recirculation ballot.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	April 2013
45-day Formal Comment Period and Initial Ballot	June 2013
10-day Recirculation Ballot	August 2013
BOT adoption	November 2013
File with FERC	December 2013

Effective Dates

See PRC-023-3 Implementation Plan.

Version History

Version	Date	Action	Change Tracking
1	February 12, 2008	Approved by Board of Trustees	New

Version	Date	Action	Change Tracking
1	March 19, 2008	Corrected typo in last sentence of Severe VSL for Requirement 3 — "then" should be "than."	Errata
1	March 18, 2010	Approved by FERC	
1	Filed for approval April 19, 2010	Changed VRF for R3 from Medium to High; changed VSLs for R1, R2, R3 to binary Severe to comply with Order 733	Revision
2	March 10, 2011 approved by Board of Trustees	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
2	March 15, 2012	FERC order issued approving PRC-023-2 (approval becomes effective May 7, 2012)	
3	TBD	Clarify applicability for consistency with PRC-025-1 and other minor corrections	Supplemental SAR (Project 2010-13.2)

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.

No new or revised term is being proposed.

A. Introduction

1. **Title:** **Transmission Relay Loadability**

2. **Number:** PRC-023-~~2~~3

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. Functional Entity:

4.1.1 Transmission Owner~~s~~ with load-responsive phase protection systems as described in PRC-023-~~2~~3 - Attachment A, applied ~~to~~at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.2 Generator Owner~~s~~ with load-responsive phase protection systems as described in PRC-023-~~2~~3 - Attachment A, applied ~~to~~at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*.

4.1.3 Distribution Provider~~s~~ with load-responsive phase protection systems as described in PRC-023-~~2~~3 - Attachment A, applied ~~to~~at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinator~~s~~

4.2. Circuits:

4.2.1 Circuits Subject to Requirements R1 – R5:

4.2.1.1 Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

4.2.1.2 Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.3 Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

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

4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.

4.2.2 Circuits Subject to Requirement R6:

4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

~~4.2.2.2~~ Transmission lines operated ~~below100~~below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES

~~**5. Effective Dates**~~

~~5.1.1.1~~4.2.2.2 ~~The effective dates of~~, except Elements that connect the ~~requirements in the PRC-023-2 standard corresponding~~GSU transformer(s) to the ~~applicable Functional Entities and circuits~~Transmission system that are ~~summarized in the following table:~~used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.

5. Effective Dates: See Implementation Plan.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, criteria 1 through 13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions. 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] [Time Horizon: Long Term Planning]*.

Criteria:

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).

2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[1] of a circuit (expressed in amperes).

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:

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

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 Requirement R1, criterion 3, using the full line inductive reactance.

[1] 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.

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).

~~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.~~

6. Not used.

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.

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.

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.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that the relays 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.

    10.1 Set load-responsive transformer fault protection relays, if used, such that the protection settings do not expose the transformer to a fault level and duration that exceeds the transformer's mechanical withstand capability[2].

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, criterion 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, for at least 15 minutes to provide time 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 set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature[3].

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:

[2] As illustrated by the "dotted line" in IEEE C57.109-1993 - *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4.

[3] IEEE standard C57.91, Tables 7 and 8, specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and Annex A cautions that bubble formation may occur above 140 degrees C.

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

b. 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.

c. Include a relay setting component of 87% of the current calculated in Requirement R1, criterion 12 in the Facility Rating determination for the circuit.

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. Each Transmission Owner, Generator Owner, and Distribution Provider shall set its out-of-step blocking elements to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, criterion ~~6,~~ 7, 8, 9, 12, or 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]*

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide an updated list of the circuits associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Maintain a list of circuits subject to PRC-023-~~2~~3 per application of Attachment B, including identification of the first calendar year in which any criterion in PRC-023-3, Attachment B applies.

6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

C. Measures

M1. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays is set according to one of the criteria in Requirement R1, criterion 1 through 13 and shall have evidence such as coordination curves or summaries of calculations that show that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. (R1)

M2. Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking elements is set to allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. (R2)

M3. Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to Requirement R1, criterion ~~6,~~ 7, 8, 9, 12, or 13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that it used the calculated circuit capability as the Facility Rating of the circuit and evidence such as dated correspondence that the resulting Facility Rating was agreed to by its associated Planning Coordinator, Transmission Operator, and Reliability Coordinator. (R3)

M4. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 2 shall have evidence such as dated correspondence to show that it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R4)

M5. Each Transmission Owner, Generator Owner, or Distribution Provider that sets transmission line relays according to Requirement R1, criterion 12 shall have evidence such as dated correspondence that it provided an updated list of the circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list. (R5)

M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it used the criteria established within PRC-023-3, Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such circuits and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area within the required timeframe. (R6)

D. Compliance

1. Compliance Monitoring Process

~~**1.1. Compliance Monitoring Responsibility**~~

~~1.2.~~1.1. ~~For entities that do not work for the Regional Entity, the Regional Entity shall serve as the~~ **Compliance Enforcement Authority**~~.~~

~~For functional entities that work for their Regional Entity, the ERO shall serve as the~~ As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority~~.~~" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

~~1.3.~~1.2. **Data Retention**

The Transmission Owner, Generator Owner, Distribution Provider and Planning Coordinator shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation to demonstrate compliance with Requirements R1 through R5 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in Requirement R6. The Planning Coordinator shall retain the most recent list of circuits in its Planning Coordinator area for which applicable entities must comply with the standard, as determined per Requirement R6.

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

The Compliance ~~Monitor~~Enforcement Authority shall keep the last audit record and all requested and submitted subsequent audit records.

~~1.4.~~1.3. **Compliance Monitoring and Assessment Processes**

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

~~1.5.~~1.4. **Additional Compliance Information**

None.

2. **Violation Severity Levels:**

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	The responsible entity did not use any one of the following criteria (Requirement R1 criterion 1 through 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~~BES for all fault conditions. OR The responsible entity did not evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees.
R2	N/A	N/A	N/A	The responsible entity failed to ensure that its out-of-step blocking elements allowed tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.
R3	N/A	N/A	N/A	The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1 criterion ~~6,~~ 7, 8, 9, 12, or 13 did not use the calculated circuit capability as the Facility Rating of the circuit.

Requirement	Lower	Moderate	High	Severe
				OR The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.
R4	N/A	N/A	N/A	The responsible entity did not provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 2 at least once each calendar year, with no more than 15 months between reports.
R5	N/A	N/A	N/A	The responsible entity did not provide its Regional Entity, with an updated list of circuits that have transmission line relays set according to the criteria established in Requirement R1 criterion 12 at least once each calendar year, with no more than 15 months between reports.
R6	N/A	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but more	The Planning Coordinator used the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.1 and 6.2, but 24	The Planning Coordinator failed to use the criteria established within Attachment B to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

Requirement	Lower	Moderate	High	Severe
		than 15 months and less than 24 months lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but failed to include the calendar year in which any criterion in Attachment B first applies. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 31 days and 45 days after the list was established or updated.	months or more lapsed between assessments. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.1 and 6.2 but provided the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area between 46 days and 60 days after list was established or updated. (part 6.2)	OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.1 and 6.2. OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to maintain the list of circuits determined according to the process described in Requirement R6. (part 6.1) OR The Planning Coordinator used the criteria established within Attachment B at least once each calendar year, with no more than 15 months between assessments to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met

Requirement	Lower	Moderate	High	Severe
		(part 6.2)		6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator area or provided the list more than 60 days after the list was established or updated. (part 6.2) OR The Planning Coordinator failed to determine the circuits in its Planning Coordinator area for which applicable entities must comply with the standard.

E. Regional Differences

None.

F. Supplemental Technical Reference Document

1. 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, June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf

PRC-023-3 — 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).

1.6. Phase overcurrent supervisory elements (i.e., phase fault detectors) associated with current-based, communication-assisted schemes (i.e., pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications.

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

2.1. 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 except as noted in section 1.6.

2.2. Protection systems intended for the detection of ground fault conditions.

2.3. Protection systems intended for protection during stable power swings.

~~**2.4.** Generator protection relays that are susceptible to load.~~

2.4. Not used.

2.5. Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017 or their successors.

2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

2.8. Relay elements associated with dc lines.

2.9. Relay elements associated with dc converter transformers.

PRC-023-3 — Attachment B

Circuits to Evaluate

- Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.
- Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the ~~BES~~Bulk Electric System.

Criteria

If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.

B1. The circuit is a monitored Facility of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Facility in the Québec Interconnection, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

B2. The circuit is a monitored Facility of an ~~IROL,~~Interconnection Reliability Operating Limit (IROL), where the IROL was determined in the planning horizon pursuant to FAC-010.

B3. The circuit forms a path (as agreed to by the Generator Operator and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

B4. The circuit is identified through the following sequence of power flow analyses[4] performed by the Planning Coordinator for the one-to-five-year planning horizon:

a. Simulate double contingency combinations selected by engineering judgment, without manual system adjustments in between the two contingencies (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

b. For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

c. When more than one Facility Rating for that circuit is available in the power flow case, the threshold for selection will be based on the Facility Rating for the loading duration nearest four hours.

d. The threshold for selection of the circuit will vary based on the loading duration assumed in the development of the Facility Rating.

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[4] Past analyses may be used to support the assessment if no material changes to the system have occurred since the last assessment

i. If the Facility Rating is based on a loading duration of up to and including four hours, the circuit must comply with the standard if the loading exceeds 115% of the Facility Rating.

ii. If the Facility Rating is based on a loading duration greater than four and up to and including eight hours, the circuit must comply with the standard if the loading exceeds 120% of the Facility Rating.

iii. If the Facility Rating is based on a loading duration of greater than eight hours, the circuit must comply with the standard if the loading exceeds 130% of the Facility Rating.

e. Radially operated circuits serving only load are excluded.

B5. The circuit is selected by the Planning Coordinator based on technical studies or assessments, other than those specified in criteria B1 through B4, in consultation with the Facility owner.

B6. The circuit is mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner.

Implementation Plan

PRC-023-3 – Transmission Relay Loadability

Project 2010-13.2 Phase II Relay Loadability

Requested Approvals

- PRC-023-3 – Transmission Relay Loadability

Requested Retirements

- PRC-023-2 – Transmission Relay Loadability

Prerequisite Approvals

- PRC-025-1 – Generator Relay Loadability*
  *A supplemental SAR was approved by the Standards Committee at their January 16-17, 2013 meeting to authorize the drafting team to make changes to PRC-023-2 to comport with the proposed draft PRC-025-1 – Generator Relay Loadability in order to establish a bright line between the applicability of load-responsive protective relays in the current transmission and the proposed generator relay loadability standards.

Revisions to Defined Terms in the NERC Glossary

- None

Background

The generator relay loadability standard drafting team and industry stakeholders raised a concern that there is no bright line to clearly distinguish which load-responsive protective relays pertain to the existing PRC-023-2 – Transmission Relay Loadability standard, effective in the United States on July 1, 2012, and the proposed PRC-025-1 – Generator Relay Loadability standard. To resolve this concern, the drafting team proposed to modify the applicability section of PRC-023-2. The standard drafting team clarified, for each functional entity, the applicability of PRC-023-2 by tying applicability to the terminal the load-responsive protective relay that it is connected to within the Transmission system.

General Considerations

It is expected that the implementation period for PRC-023-2 will have been achieved, in part, by the time PRC-023-3 is adopted by the NERC Board of Trustees and by the time of other approvals by applicable

governmental authorities. The proposed PRC-023-3 Implementation Plan now reflects specific milestone dates that are known time periods consistent with PRC-023-2.

Applicable Entities

- Distribution Provider
- Generator Owner
- Planning Coordinator
- Transmission Owner

Effective Date

New Standard

PRC-023-3	First day of the first calendar quarter 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 calendar quarter 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.

Standards for Retirement

PRC-023-2	Midnight of the day immediately prior to the Effective Date of PRC-023-3 – Transmission Relay Loadability in the particular jurisdiction in which the new standard is becoming effective, except Requirement R1, Criterion 6 which will remain in force until the effective date of PRC-025-1.

Implementation Plan for Definitions

No definitions are proposed as a part of this standard.

Implementation Plan for PRC-023-3, Requirements R1 through R6

Each Distribution Provider, Generator Owner, Planning Coordinator, and Transmission Owner applicable to this standard shall be 100% compliant on the following dates:

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1	Each Transmission Owner, Generator Owner, and Distribution Provider with load-responsive phase protection systems on transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above, except as noted below.	First day of the first calendar quarter, after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
	• For supervisory elements as described in PRC-023-3 - Attachment A, Section 1.6	The later of July 1, 2014 or first day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
	• For switch-on-to-fault schemes as described in PRC-023-3 - Attachment A, Section 1.3	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1 (continued)	Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date
R2 and R3	Each Transmission Owner, Generator Owner, and Distribution Provider with load-responsive phase protection systems on transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R2 and R3 continued	Each Transmission Owner, Generator Owner, and Distribution Provider with load-responsive phase protection systems on circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date
R4	Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability	First day of the first calendar quarter six months after applicable regulatory approvals	First day of the first calendar quarter six months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R5	Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
R6 (including parts 6.1 and 6.2)	Each Planning Coordinator shall conduct an assessment by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owner, and Distribution Providers must comply with Requirements R1 through R5	Later of January 1, 2014 or the first day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Revisions or Retirements to Already Approved Standards

The following table identifies the sections of the approved standard that shall be added, retired, or revised when this standard is implemented. If the drafting team is recommending revisions, those changes are identified by the "Proposed Replacement" column.

Already Approved Standard	Proposed Replacement
PRC-023-2 **4.1.** Functional Entity **4.1.1** Transmission Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* **4.1.2** Generator Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* **4.1.3** Distribution Providers with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1*(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities. **4.1.4** Planning Coordinators	**PRC-023-3** **4.1.** Functional Entity **4.1.1** Transmission Owner with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* **4.1.2** Generator Owner with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5).* **4.1.3** Distribution Provider with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 *(Circuits Subject to Requirements R1 – R5)*, provided those circuits have bi-directional flow capabilities. **4.1.4** Planning Coordinator
Notes: The change in the proposed PRC-023-3 Applicability, Section 4.1, Functional Entity creates a bright line between those load-responsive protective relays that are applicable to PRC-023-3 – Transmission Relay Loadability and the proposed PRC-025-1 – Generator Relay Loadability. This is evident by the minor changes to the Applicability text to distinguish the applicability of the relays by which "terminal" the load-responsive protective relay is connected to within the Transmission system. Applicability is established by ownership of the load-responsive protective relays, not the Facilities.	

Already Approved Standard	Proposed Replacement
PRC-023-2 **4.2.** Circuits **4.2.1** Circuits Subject to Requirements R1 – R5 **4.2.1.1** Transmission lines operated at 200 kV and above. **4.2.1.2** Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6. **4.2.1.3** Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6. **4.2.1.4** Transformers with low voltage terminals connected at 200 kV and above. **4.2.1.5** Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6. **4.2.1.6** Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6. **4.2.2** Circuits Subject to Requirement R6	**PRC-023-3** **4.2.** Circuits **4.2.1** Circuits Subject to Requirements R1 – R5 **4.2.1.1** Transmission lines operated at 200 kV and above, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. **4.2.1.2** Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6. **4.2.1.3** Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6. **4.2.1.4** Transformers with low voltage terminals connected at 200 kV and above. **4.2.1.5** Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6. **4.2.1.6** Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6. **4.2.2** Circuits Subject to Requirement R6

Already Approved Standard	Proposed Replacement
4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV **4.2.2.2** Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES	**4.2.2.1** Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. **4.2.2.2** Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads.
Notes: The change in the proposed PRC-023-3 Applicability, Section 4.1 Facilities, creates a bright line between those Facilities that are applicable to PRC-023-3 – Transmission Relay Loadability and those Facilities in the proposed PRC-025-1 – Generator Relay Loadability. This is achieved by excluding Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant while allowing these Elements to also supply generating plant loads. Plant loads may include situations like pumped storage facilities where the generating plant also serves as a load for pumping. The above applicability items for Section 4.2 "Circuits" that are subject to the standard were modified to exclude those Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. The added text reads: "except Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads" and is found in Sections 4.2.1.1, 4.2.2.1, and 4.2.2.2. This eliminates an overlap with PRC-025-1 and places the performance for lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network under the proposed PRC-025-1 with the understanding that these Elements may also supply generating plant loads.	

Already Approved Standard	Proposed Replacement
PRC-023-2 (Retirement) R1, Criterion 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."	**PRC-025-1 (New)** **New Requirement** R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]* *Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria, Options 14 through 19. (See standard for details)
Notes: The Transmission Owner and Distribution Provider were added to the Applicability of the proposed PRC-025-1 and excluded Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. Elements may also supply generating plant loads. Therefore, Requirement R1, Criterion 6 has been removed from the proposed standard PRC-023-3 because this criterion is now replaced (i.e., superseded) by the proposed PRC-025-1 – Generator Relay Loadability standard, Requirement R1 and its Attachment 1: Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria, Options 14 through 19. Applicability concerning generation Facilities is now addressed in the proposed PRC-025-1. Although, Requirement R1, Criterion 6 is not shown in the proposed PRC-023-3, it remains auditable while each entity assures its compliance with the proposed PRC-025-1 criteria according to the provided Implementation Plan(s).	
PRC-023-2 (Retirement) R1, Attachment A, exclusion 2.4. "Generator protection relays that are susceptible to load."	**None.**
Notes: This exclusion has been superseded by the proposed PRC-025-1 standard that pertains to these relays. The proposed PRC-023-3 standard does not include any criteria that are relevant to generator protection relays. The proposed PRC-025-1 standard establishes specific criteria for generator load-responsive protective relays, and renders this exclusion unnecessary.	

Implementation Plan

PRC-023-3 – Transmission Relay Loadability

Project 2010-13.2 Phase II Relay Loadability

Requested Approvals

- PRC-023-3 – Transmission Relay Loadability

Requested Retirements

- PRC-023-2 – Transmission Relay Loadability

Prerequisite Approvals

- PRC-025-1 – Generator Relay Loadability*
  *A supplemental SAR was approved by the Standards Committee at their January 16-17, 2013 meeting to authorize the drafting team to make changes to PRC-023-2 to comport with the proposed draft PRC-025-1 – Generator Relay Loadability in order to establish a bright line between the applicability of load-responsive protective relays in the current transmission and the proposed generator relay loadability standards.

Revisions to Defined Terms in the NERC Glossary

- None

Background

The generator relay loadability standard drafting team and industry stakeholders raised a concern that there is no bright line to clearly distinguish which load-responsive protective relays pertain to the existing PRC-023-2 – Transmission Relay Loadability standard, effective in the United States on July 1, 2012, and the proposed PRC-025-1 – Generator Relay Loadability standard. To resolve this concern, the drafting team proposed to modify the applicability section of PRC-023-2. The standard drafting team clarified, for each functional entity, the applicability of PRC-023-2 by tying applicability to the terminal the load-responsive protective relay that it is connected to within the Transmission system.

General Considerations

It is expected that the implementation period for PRC-023-2 will have been achieved, in part, by the time PRC-023-3 is adopted by the NERC Board of Trustees and by the time of other approvals by applicable

governmental authorities. The proposed PRC-023-3 Implementation Plan now reflects specific milestone dates that are known time periods consistent with PRC-023-2.

Applicable Entities

- Distribution Provider
- Generator Owner
- Planning Coordinator
- Transmission Owner

Effective Date

New Standard

PRC-023-3	First day of the first calendar quarter 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 calendar quarter 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.

Standards for Retirement

PRC-023-2	Midnight of the day immediately prior to the Effective Date of PRC-023-3 – Transmission Relay Loadability in the particular jurisdiction in which the new standard is becoming effective, except Requirement R1, Criterion 6 which will remain in force until the effective date of PRC-025-1.

Implementation Plan for Definitions

No definitions are proposed as a part of this standard.

Implementation Plan for PRC-023-3, Requirements R1 through R6

Each Distribution Provider, Generator Owner, Planning Coordinator, and Transmission Owner applicable to this standard shall be 100% compliant on the following dates:

Requirement	Applicability	Implementation Date: Jurisdictions where Regulatory Approval is Required	Implementation Date: Jurisdictions where No Regulatory Approval is Required
R1	Each Transmission Owner, Generator Owner, and Distribution Provider with load-responsive phase protection systems on transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above, except as noted below.	First day of the first calendar quarter, after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
	• For supervisory elements as described in PRC-023-3 - Attachment A, Section 1.6	The later of July 1, 2014 or first day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
	• For switch-on-to-fault schemes as described in PRC-023-3 - Attachment A, Section 1.3	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R1 (continued)	Each Transmission Owner, Generator Owner, and Distribution Provider with circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date
R2 and R3	Each Transmission Owner, Generator Owner, and Distribution Provider with load-responsive phase protection systems on transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R2 and R3 continued	Each Transmission Owner, Generator Owner, and Distribution Provider with load-responsive phase protection systems on circuits identified by the Planning Coordinator pursuant to Requirement R6	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit's inclusion on a list of circuits per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date
R4	Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability	First day of the first calendar quarter six months after applicable regulatory approvals	First day of the first calendar quarter six months after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Requirement	Applicability	Implementation Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
R5	Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12	First day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities
R6 **(including parts 6.1 and 6.2)**	Each Planning Coordinator shall conduct an assessment by applying the criteria in Attachment B to determine the circuits in its Planning Coordinator area for which Transmission Owners, Generator Owner, and Distribution Providers must comply with Requirements R1 through R5	Later of January 1, 2014 or the first day of the first calendar quarter after applicable regulatory approvals	First day of the first calendar quarter after Board of Trustees adoption, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities

Revisions or Retirements to Already Approved Standards

The following table identifies the sections of the approved standard that shall be added, retired, or revised when this standard is implemented. If the drafting team is recommending revisions, those changes are identified by the “Proposed Replacement” column.

<table>
<tr><th>Already Approved Standard</th><th>Proposed Replacement</th></tr>
<tr><td>PRC-023-2
4.1. Functional Entity
4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1 (Circuits Subject to Requirements R1 – R5).
4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1 (Circuits Subject to Requirements R1 – R5).
4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1(Circuits Subject to Requirements R1 – R5), provided those circuits have bi-directional flow capabilities.
4.1.4 Planning Coordinators</td><td>PRC-023-3
4.1. Functional Entity
4.1.1 Transmission Owner~~s~~ with load-responsive phase protection systems as described in PRC-023-~~2~~3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (Circuits Subject to Requirements R1 – R5).
4.1.2 Generator Owner~~s~~ with load-responsive phase protection systems as described in PRC-023-3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (Circuits Subject to Requirements R1 – R5).
4.1.3 Distribution Provider~~s~~ with load-responsive phase protection systems as described in PRC-023-~~2~~3 - Attachment A, applied at the terminals of the circuits defined in 4.2.1 (Circuits Subject to Requirements R1 – R5), provided those circuits have bi-directional flow capabilities.
4.1.4 Planning Coordinator~~s~~</td></tr>
<tr><td colspan="2">Notes: The change in the proposed PRC-023-3 Applicability, Section 4.1, Functional Entity creates a bright line between those load-responsive protective relays that are applicable to PRC-023-3 – Transmission Relay Loadability and the proposed PRC-025-1 – Generator Relay Loadability. This is evident by the minor changes to the Applicability text to distinguish the applicability of the relays by which “terminal” the load-responsive protective relay is connected to within the Transmission system. Applicability is established by ownership of the load-responsive protective relays, not the Facilities.</td></tr>
</table>

Already Approved Standard	Proposed Replacement
PRC-023-2 **4.2.** Circuits **4.2.1** Circuits Subject to Requirements R1 – R5 **4.2.1.1** Transmission lines operated at 200 kV and above. **4.2.1.2** Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6. **4.2.1.3** Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6. **4.2.1.4** Transformers with low voltage terminals connected at 200 kV and above. **4.2.1.5** Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with R6. **4.2.1.6** Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with R6.	**PRC-023-3** **4.2.** Circuits **4.2.1** Circuits Subject to Requirements R1 – R5 **4.2.1.1** Transmission lines operated at 200 kV and above, except ~~lines~~Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~to the network~~. Elements may also supply generating plant loads. **4.2.1.2** Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6. **4.2.1.3** Transmission lines operated below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6. **4.2.1.4** Transformers with low voltage terminals connected at 200 kV and above. **4.2.1.5** Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator in accordance with Requirement R6. **4.2.1.6** Transformers with low voltage terminals connected below 100 kV that are part of the BES and selected by the Planning Coordinator in accordance with Requirement R6.
4.2.2 Circuits Subject to Requirement R6	**4.2.2** Circuits Subject to Requirement R6

Already Approved Standard	Proposed Replacement
4.2.2.1 Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV **4.2.2.2** Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES	**4.2.2.1** Transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, except ~~lines and transformers~~Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~to the network~~. Elements may also supply generating plant loads. **4.2.2.2** Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES, except ~~lines and transformers~~Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~to the network~~. Elements may also supply generating plant loads.
Notes: The change in the proposed PRC-023-3 Applicability, Section 4.1 Facilities, creates a bright line between those Facilities that are applicable to PRC-023-3 – Transmission Relay Loadability and those Facilities in the proposed PRC-025-1 – Generator Relay Loadability. This is achieved by excluding Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant while allowing these Elements to also supply generating plant loads. Plant loads may include situations like pumped storage facilities where the generating plant also serves as a load for pumping. The above applicability items for Section 4.2 "Circuits" that are subject to the standard were modified to exclude those ~~lines and transformers~~Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~to the network~~. Elements may also supply generating plant loads. The added text reads: "except ~~lines and transformers~~Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant ~~to the network~~. Elements may also supply generating plant loads" and is found in Sections 4.2.1.1, 4.2.2.1, and 4.2.2.2. This eliminates an overlap with ~~the proposed changes in~~ PRC-025-1 and places the performance for lines and transformers that are used exclusively to export energy directly from a BES generating unit or generating plant to the network under the proposed PRC-025-1~~.~~ with the understanding that these Elements may also supply generating plant loads.	

Already Approved Standard	Proposed Replacement
PRC-023-2 (Retirement) R1, Criterion 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."	**PRC-025-1 (New)** **New Requirement** R1. Each Generator Owner, Transmission Owner, and Distribution Provider shall apply settings that are in accordance with PRC-025-1 – Attachment 1: Relay Settings, on each load-responsive protective relay while maintaining reliable fault protection. *[Violation Risk Factor: High] [Time Horizon: Long-Term Planning]* *Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria, Options 14 through 19. (See standard for details)
Notes: The Transmission Owner and Distribution Provider were added to the Applicability of the proposed PRC-025-1 and excluded ~~lines~~Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a ~~Bulk Electric System (~~BES~~)~~ generating unit or generating plant~~ to the network; therefore~~. Elements may also supply generating plant loads. Therefore, Requirement R1, Criterion 6 has been removed from the proposed standard PRC-023-3 because this criterion is now replaced (i.e., superseded) by the proposed PRC-025-1 – Generator Relay Loadability standard, Requirement R1 and its Attachment 1: Attachment 1: Relay Settings, Table 1: Relay Loadability Evaluation Criteria, Options 14 through 19. Applicability concerning generation Facilities is now addressed in the proposed PRC-025-1. Although, Requirement R1, Criterion 6 is not shown in the proposed PRC-023-3, it remains auditable while each entity assures its compliance with the proposed PRC-025-1 criteria according to the provided Implementation Plan(s).	
PRC-023-2 (Retirement) R1, Attachment A, exclusion 2.4. "Generator protection relays that are susceptible to load."	**None.**
Notes: This exclusion has been superseded by the proposed PRC-025-1 standard that pertains to these relays. The proposed PRC-023-3 standard does not include any criteria that are relevant to generator protection relays. The proposed PRC-025-1 standard establishes specific criteria for generator load-responsive protective relays, and renders this exclusion unnecessary.	

Standards Announcement

Project 2010-13.2 Phase 2 of Relay Loadability: Generation PRC-023-3

Final Ballot for PRC-023-3 is now open through September 13, 2013

Now Available

A final ballot for **PRC-023-3** – Transmission Relay Loadability is now being conducted through **8 p.m. Eastern on Friday, September 13, 2013**.

Background information for this project can be found on the project page.

Instructions

In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the final ballot window. If a ballot pool member does not participate in the final ballot, that member's vote cast in the previous ballot will be carried over as that member's vote in the final ballot.

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

Next Steps

Voting results for the standard will be posted and announced after the ballot window closes. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

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

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

Standards Announcement

Project 2010-13.2 Phase 2 of Relay Loadability: Generation PRC-023-3

Final Ballot Results

Now Available

A final ballot for **PRC-023-3** – Transmission Relay Loadability concluded at **8 p.m. Eastern on Friday, September 13, 2013**.

Voting statistics for the final ballot are listed below, and the Ballot Results page provides a link to the detailed results. This standard achieved a quorum and sufficient affirmative votes for approval.

Approval
Quorum: 85.93 % Approval: 90.83 %

Background information for this project can be found on the project page.

Next Steps

Voting results for the standard will be posted and announced after the ballot window closes. The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Standards Development Process

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

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results	
Ballot Name:	Project 2010-13.2 PRC-023 Ballot_1 July 2013
Ballot Period:	9/4/2013 - 9/13/2013
Ballot Type:	
Total # Votes:	336
Total Ballot Pool:	391
Quorum:	**85.93 % The Quorum has been reached**
Weighted Segment Vote:	90.83 %
Ballot Results:	**The standard has passed.**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	108	1	73	0.924	6	0.076	0	9	20
2 - Segment 2	9	0.7	7	0.7	0	0	0	0	2
3 - Segment 3	86	1	60	0.87	9	0.13	0	6	11
4 - Segment 4	29	1	17	0.85	3	0.15	0	4	5
5 - Segment 5	90	1	64	0.842	12	0.158	0	6	8
6 - Segment 6	54	1	41	0.872	6	0.128	0	0	7
7 - Segment 7	1	0	0	0	0	0	0	0	1
8 - Segment 8	4	0.3	3	0.3	0	0	0	0	1
9 - Segment 9	1	0.1	1	0.1	0	0	0	0	0
10 - Segment 10	9	0.9	9	0.9	0	0	0	0	0
Totals	**391**	**7**	**275**	**6.358**	**36**	**0.642**	**0**	**25**	**55**

Individual Ballot Pool Results

Segment	**Organization**	**Member**	**Ballot**	**NERC Notes**
1	Ameren Services	Eric Scott	Affirmative	
1	American Electric Power	Paul B Johnson	Affirmative	
1	American Transmission Company, LLC	Andrew Z Pusztai	Abstain	
1	Arizona Public Service Co.	Robert Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	ATCO Electric	Glen Sutton	Affirmative	

1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Affirmative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Affirmative	
1	Big Rivers Electric Corp.	Chris Bradley		
1	Bonneville Power Administration	Donald S. Watkins	Negative	
1	Brazos Electric Power Cooperative, Inc.	Tony Kroskey		
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Affirmative	
1	Central Maine Power Company	Joseph Turano Jr.		
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	CPS Energy	Richard Castrejana	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	El Paso Electric Company	Dennis Malone		
1	Entergy Transmission	Oliver A Burke	Abstain	
1	FirstEnergy Corp.	William J Smith	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Abstain	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Georgia Transmission Corporation	Jason Snodgrass	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Bob Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Affirmative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	Imperial Irrigation District	Tino Zaragoza		
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	JDRJC Associates	Jim D Cyrulewski	Affirmative	
1	JEA	Ted Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon		
1	Kansas City Power & Light Co.	Jennifer Flandermeyer	Affirmative	
1	Keys Energy Services	Stanley T Rzad		
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	John Burnett	Abstain	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Affirmative	
1	Manitoba Hydro	Nazra S Gladu	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	Memphis Light, Gas and Water Division	Allan Long		
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Affirmative	
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Cole C Brodine		
1	New Brunswick Power Transmission Corporation	Randy MacDonald		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Affirmative	
1	Northeast Utilities	David Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Affirmative	
1	Omaha Public Power District	Doug Peterchuck	Affirmative	

1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Orlando Utilities Commission	Brad Chase	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Pacific Gas and Electric Company	Bangalore Vijayraghavan		
1	PacifiCorp	Ryan Millard	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Abstain	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Affirmative	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Public Utility District No. 1 of Okanogan County	Dale Dunckel	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Affirmative	
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	San Diego Gas & Electric	Will Speer		
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Sho-Me Power Electric Cooperative	Denise Stevens	Affirmative	
1	Sierra Pacific Power Co.	Rich Salgo		
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Affirmative	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	
1	Tennessee Valley Authority	Howell D Scott	Affirmative	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State G & T Association, Inc.	Tracy Sliman	Affirmative	
1	Tucson Electric Power Co.	John Tolo		
1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Barbara Constantinescu	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman	Affirmative	
2	Midwest ISO, Inc.	Marie Knox	Affirmative	
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	PJM Interconnection, L.L.C.	stephanie monzon		
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Affirmative	
3	Alabama Power Company	Robert S Moore	Negative	
3	Alameda Municipal Power	Douglas Draeger		
3	Ameren Services	Mark Peters	Affirmative	
3	Associated Electric Cooperative, Inc.	Chris W Bolick	Affirmative	
3	Atlantic City Electric Company	NICOLE BUCKMAN	Affirmative	
3	Avista Corp.	Scott J Kinney	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blue Ridge Electric	James L Layton		
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	Central Electric Power Cooperative	Adam M Weber	Affirmative	
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy		
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	Colorado Springs Utilities	Charles Morgan	Affirmative	
3	ComEd	John Bee	Affirmative	

3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	CPS Energy	Jose Escamilla	Abstain	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Negative	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	El Paso Electric Company	Tracy Van Slyke		
3	Entergy	Joel T Plessinger	Abstain	
3	FirstEnergy Corp.	Cindy E Stewart	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power Corporation	Lee Schuster		
3	Georgia Power Company	Danny Lindsey	Negative	
3	Great River Energy	Brian Glover	Negative	
3	Gulf Power Company	Paul C Caldwell	Negative	
3	Hydro One Networks, Inc.	David Kiguel	Affirmative	
3	Imperial Irrigation District	Jesus S. Alcaraz		
3	JEA	Garry Baker	Affirmative	
3	KAMO Electric Cooperative	Theodore J Hilmes		
3	Kansas City Power & Light Co.	Charles Locke	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Mississippi Power	Jeff Franklin	Negative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	John S Bos		
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	David R Rivera	Affirmative	
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Negative	
3	NW Electric Power Cooperative, Inc.	David McDowell	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Affirmative	
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	PacifiCorp	Dan Zollner	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Portland General Electric Co.	Thomas G Ward	Abstain	
3	Potomac Electric Power Co.	Mark Yerger	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Puget Sound Energy, Inc.	Erin Apperson		
3	Rayburn Country Electric Coop., Inc.	Eddy Reece		
3	Rutherford EMC	Thomas M Haire	Abstain	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Affirmative	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Affirmative	
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey	Affirmative	
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-County Electric Cooperative, Inc.	Mike Swearingen	Abstain	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Affirmative	
3	Westar Energy	Bo Jones	Affirmative	
3	Wisconsin Electric Power Marketing	James R Keller	Affirmative	
3	Wisconsin Public Service Corp.	Gregory J Le Grave	Affirmative	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	

4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle		
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Constellation Energy Control & Dispatch, L.L.C.	Margaret Powell	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Detroit Edison Company	Daniel Herring	Negative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Cairo Vanegas		
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Imperial Irrigation District	Diana U Torres		
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Integrys Energy Group, Inc.	Christopher Plante	Affirmative	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Modesto Irrigation District	Spencer Tacke	Negative	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steven McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Affirmative	
5	AEP Service Corp.	Brock Ondayko	Affirmative	
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke		
5	BC Hydro and Power Authority	Clement Ma	Affirmative	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Affirmative	
5	BrightSource Energy, Inc.	Chifong Thomas	Abstain	
5	Calpine Corporation	Hamid Zakery	Negative	
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman	Negative	
5	Cogentrix Energy Power Management, LLC	Mike D Hirst	Affirmative	
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	CPS Energy	Robert Stevens	Affirmative	
5	Dairyland Power Coop.	Tommy Drea	Affirmative	
5	Detroit Edison Company	Alexander Eizans	Negative	
5	Detroit Renewable Power	Marcus Ellis	Abstain	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	El Paso Electric Company	Gustavo Estrada		
5	Essential Power, LLC	Patrick Brown	Abstain	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Affirmative	
5	FirstEnergy Solutions	Kenneth Dresner	Affirmative	

5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Negative	
5	Hydro-Québec Production	Roger Dufresne	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff	Negative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Karin Schweitzer	Negative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	S N Fernando	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Affirmative	
5	MEAG Power	Steven Grego	Affirmative	
5	MidAmerican Energy Co.	Neil D Hammer	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Negative	
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	North Carolina Electric Membership Corp.	Jeffrey S Brame	Negative	
5	Northern Indiana Public Service Co.	William O. Thompson	Negative	
5	Occidental Chemical	Michelle R DAntuono	Affirmative	
5	Oglethorpe Power Corporation	Bernard Johnson	Affirmative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Affirmative	
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	PacifiCorp	Bonnie Marino-Blair	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	PSEG Fossil LLC	Tim Kucey	Affirmative	
5	Public Utility District No. 1 of Chelan County	John Yale		
5	Public Utility District No. 1 of Lewis County	Steven Grega	Abstain	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell	Affirmative	
5	Puget Sound Energy, Inc.	Lynda Kupfer	Affirmative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Affirmative	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic		
5	South Feather Power Project	Kathryn Zancanella	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	
5	Tri-State G & T Association, Inc.	Mark Stein	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Utility System Effeciencies, Inc. (USE)	Robert L Dintelman	Affirmative	
5	Westar Energy	Bryan Taggart	Affirmative	
5	Western Farmers Electric Coop.	Clem Cassmeyer	Negative	
5	Wisconsin Electric Power Co.	Linda Horn	Affirmative	
5	Wisconsin Public Service Corp.	Scott E Johnson	Affirmative	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	
6	AEP Marketing	Edward P. Cox	Affirmative	
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	City of Austin dba Austin Energy	Lisa L Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	

6	Constellation Energy Commodities Group	David J Carlson	Affirmative	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil		
6	El Paso Electric Company	Luis Rodriguez		
6	FirstEnergy Solutions	Kevin Querry	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Affirmative	
6	Great River Energy	Donna Stephenson	Negative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Affirmative	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	MidAmerican Energy Co.	Dennis Kimm	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Negative	
6	New York Power Authority	Saul Rojas	Affirmative	
6	Northern California Power Agency	Steve C Hill	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	
6	NRG Energy, Inc.	Alan Johnson		
6	Omaha Public Power District	Douglas Collins	Affirmative	
6	PacifiCorp	Kelly Cumiskey	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Ty Bettis		
6	Power Generation Services, Inc.	Stephen C Knapp		
6	PPL EnergyPlus LLC	Elizabeth Davis	Affirmative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	Steven J Hulet	Affirmative	
6	Santee Cooper	Michael Brown	Affirmative	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	Southern California Edison Company	Lujuanna Medina	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Westar Energy	Grant L Wilkerson		
6	Western Area Power Administration - UGP Marketing	Peter H Kinney	Affirmative	
6	Wisconsin Public Service Corp.	David Hathaway	Affirmative	
6	Xcel Energy, Inc.	David F Lemmons	Affirmative	
7	Alcoa, Inc.	Thomas Gianneschi		
8		Debra R Warner	Affirmative	
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Southwest Power Pool RE	Emily Pennel	Affirmative	
10	Texas Reliability Entity, Inc.	Donald G Jones	Affirmative	
10	Western Electricity Coordinating Council	Steven L. Rueckert	Affirmative	

Exhibit E

Unit Auxiliary Transformer (UAT) Relay Loadability Report

Exhibit E—Unit Auxiliary Transformer (UAT) Relay Loadability Report

Background and Objective

Reliability Standard, PRC-025-1 – Generator Relay Loadability (standard), developed under NERC Project 2010-13.2 – Phase 2 of Relay Loadability: Generation, was adopted by the NERC Board of Trustees (Board) on August 15, 2013. Subsequent to the standard's adoption, the Board asked if a potential reliability gap exists on load-responsive protective relays that are installed on the low-voltage side of the unit auxiliary transformer (UAT). Only the relays installed on the high-voltage side of the UAT are applicable to the standard. The request by the Board was in response to unresolved minority comments made by industry stakeholders arguing that relays on the low-voltage side of the UAT should be applicable to the standard.

In response to the Board's question, the standard drafting team conducted a basic study to investigate whether relays on the low-voltage side of the UAT experience loadability challenges during the stressed system conditions anticipated by the standard. Additional information regarding the basis for the standard and its criteria is found in the Guidelines and Technical Basis section of the standard or on the Project 2010-13.2[1] project page. The approach of this study was to develop a model for an actual event that presented a depressed voltage to the plant's auxiliary systems and validate that model using recorded data from that event. The study data was used to determine the expected relay loadability response on the low-voltage side of the UAT under the stressed system conditions and to determine if the low-voltage side relays are challenged by the loadability conditions addressed in the standard.

Approach

Using the Electrical Transient Analyzer Program® (ETAP) modeling software, a basic model of an actual generating plant's auxiliary system was built and is shown in the Appendix. A composite model of plant auxiliary equipment (connected load) such as motors, station service transformers, and variable frequency drives was used because actual event data facilitated fine tuning of the model to match the actual event. This resulted in composite loads being placed at four low-voltage side buses to represent the connected load.

Two different low-voltages were used to be representative of a typical generating plant's auxiliary systems. The load on both the 7 kV and 4 kV buses were a mixture of impedance type loads with induction motors. The 7kV bus load was 75-80% induction motors and the 4 kV bus load was 70-75% induction motor. The simplified bus loads, modeled as composite loads, were determined to have sufficient accuracy.

A digital fault recorder (DFR) captured an actual event at the plant being modeled where the balanced three phase voltage was depressed to approximately 85% of the nominal system voltage, representative of the stressed system conditions. The event lasted for approximately 0.4 seconds with the generating unit(s) remaining on-line during and after the event. The generator excitation system responded as expected by increasing field voltage to support the automatic voltage regulator generator voltage setpoint.

[1] http://www.nerc.com/pa/Stand/Pages/Project-2010-13-2-Phase-2-Relay-Loadability-Generation.aspx

Additional analysis was performed using the Siemens PTI PSS®E powerflow and transient stability analysis software. This additional analysis was used to assess the time-varying nature of the station service load.

Model Validation

The ETAP plant model was verified using real-time data from the on-site DFR and revenue meter. Table 1 shows a comparison between the available field data and results from the ETAP load flow simulation for the normal operating condition. All results were within ±2%; except for generator gross MVAR (5.9%) which is negligible for this study. The simulation results when compared to the DFR event data confirm that the model is accurate for this steady state operating condition and suitable for the study.

Table 1. ETAP Study Model Validation		
Generator/Switchyard Values	**DFR**	**ETAP**
Gen kV	19.76	19.78
Gen kA	24.37	24.3
Switchyard kV (Transmission)	348.53	348.5
MW (gross)	827	827
MVAR (gross)	102	96
Auxiliaries	**DFR**	**ETAP**
UAT 2-1 High-side kA	Not captured	0.92
2A1 kA	1.29	1.28
2B1 kA	2.08	2.1
UAT 2-2 High-side kA	Not captured	1.03
2A2 kA	1.3	1.3
2B2 kA, 12B2	2.48	2.45

ETAP Simulation Results

Two studies were conducted. Study 1 simulated the expected results on the low-voltage side of the UAT based on the actual event modeled. The low-voltage buses in Study 1 observed current changes ranging from 6.8% to 10%, versus -1.9% to 8.1% for the actual event as shown in Table 2. Thus the results from Study 1 are conservative and provide additional margin. The percentage difference in 4kV bus load currents in the study comparing the ETAP values to field results (10%) are attributed to using a single composite lump load. In order to obtain ETAP values closer to the field results, a detailed model for motors and impedance loads at each 4kV bus would be required. Since the information would be difficult to obtain, it is not feasible to perform the study in the time allowed. The ETAP study also does not consider the effects of field forcing the AVR would contribute during the time frame of the event.

While the study was performed for one plant auxiliary configuration using approximately a 70% to 80% inductive load ratio depending on the bus loading, the types of auxiliary load (e.g., pumps, fans, compressors, and other impedance loads) are common to all generating units and generating plants. The primary difference among various types of generating units and plants are the quantity and size of the loads. Thus, the percent current increases in response to depressed voltage are typical values that would be expected for other plant auxiliary configurations.

The results in Table 2 for this particular event (Study 1) indicate there are small changes in current on the low-voltage side of the UAT. The standard drafting team theorizes that the ratio of induction motor load to constant impedance load resulted in a low overall increase in current. During stressed system conditions, induction type loads tend to have an increase current while impedance type loads tend to have a decrease in current.

Since inductive loads are constant kilovolt ampere (kVA) loads which will increase current in response to a depressed voltage, a second study (Study 2) was conducted to test the sensitivity of the Study 1 results. To test the expected range of increased current, Study 2 simulated the low-voltage side of the UAT by holding the total kVA load constant while increasing the inductive load ratio to 90% at each bus and is only used in this study to illustrate a relative magnitude increase in current for the 85% stressed system voltage condition. Using a value higher than 90% is not practical as all generating unit and plant configurations have some level of constant impedance loading. Table 3 lists the percent increase in current resulting from the 90% inductive load ratio. The low-voltage buses in Study 2 observed current changes ranging from 11.0 to 14.4%.

Table 2. ETAP Study 1 at 85% Transmission Voltage to Event Conditions						
Generator & Switchyard	**Pre (Actual)**	**Pre (ETAP)**	**During (Actual)**	**During (ETAP)**		
Gen kV	19.7	19.7	17.29	17.24		
Gen kA	20.2	20.17	24.14	23.89		
Gen MW (gross)	688	688	688	688		
Gen MVAR (gross)	2	15	159	188		
Auxiliaries	**Pre (Actual)**	**Pre (ETAP)**	**During (Actual)**	**During (ETAP) Study 1**	**% Change (Actual)**	**% Change (ETAP) Study 1**
UAT 2-1 HS kA	-	0.88	-	0.94	-	6.8
2A1 kA (7 kV)	1.23	1.23	1.3	1.34	5.7	8.9
2B1 kA (4 kV)	1.97	1.95	1.92	2.09	-2.4	7.2
UAT 2-2 HS kA	-	1.0	-	1.09	-	9.0
2A2 kA (7 kV)	1.49	1.5	1.61	1.65	8.1	10.0
Composite 2B2 , 12B2 (4 kV)	2.14	2.12	2.1	2.27	-1.9	7.1

Table 3. ETAP Study 2 at 85% Transmission Voltage with Higher Inductive UAT Loading						
Generator & Switchyard	**Pre (Actual)**	**Pre (ETAP)**	**During (Actual)**	**During (ETAP)**		
Gen kV	19.7	19.7	17.29	17.24		
Gen kA	20.2	20.17	24.14	23.89		
Gen MW (gross)	688	688	688	688		
Gen MVAR (gross)	2	15	159	188		
Auxiliaries	**Pre (Actual)**	**Pre (ETAP)**	**During (Actual)**	**During (ETAP) Study 2**	**% Change (Actual)**	**% Change (ETAP) Study 2**
UAT 2-1 HS kA	-	0.88	-	0.99	-	12.5
2A1 kA (7 kV)	1.23	1.23	1.3	1.38	5.7	12.2
2B1 kA (4 kV)	1.97	1.95	1.92	2.23	-2.4	14.4
UAT 2-2 HS kA	-	1.0	-	1.11	-	11.0
2A2 kA (7 kV)	1.49	1.5	1.61	1.68	8.1	12.0
Composite 2B2 , 12B2 (4 kV)	2.14	2.12	2.1	2.39	-1.9	12.7

PSS®E Model and Simulation Results

The station service model used in the ETAP analysis was added to a 955 MVA generating unit in the Eastern Interconnection model. This generating unit is similar in size to the unit modeled in the ETAP analysis. The unit in the PSS®E model was selected because it was one the units used in simulations supporting the NERC System Protection and Control Subcommittee (SPCS) *Power Plant and Transmission System Protection Coordination* report, which was one of the reference documents used in development of PRC-025-1. This generating unit also is one for which recorded data is available from the August 14, 2003 event. This unit is located in western Michigan and responded to a depressed transmission system voltage until the local transmission voltage recovered after the east-west system separation occurred.

The model was modified to account for a difference in generator terminal voltage by adjusting the UAT turns ratio. The PSS®E complex load model (CLOD) was used to represent the station service load using the same percentages of large motor load and constant impedance load as the ETAP Study 1 (75-80% for the 7 kV buses and 70-75% for the 4 kV buses).

The simulation is based on the "synchronous generator simulation criteria" described in the Guidelines and Technical Basis of PRC-025-1. In this method a reactor is switched on the high-voltage side of the generator step-up (GSU) transformer to lower the transmission system voltage to 0.85 per unit prior to response of the generator excitation system. In these simulations the maximum load current on the UAT occurs when the station service load responds to the initial voltage drop. The load current is reduced as the generator increases its reactive output to support its terminal voltage. A maximum excitation limiter (MEL) was modeled in the simulation. As the MEL reduces the reactive output of the generator, the generator and station service voltage decrease. As a result, the load current increases and settles at a level higher than the pre-event current, but lower than the maximum observed current. For the conditions modeled in this simulation, the MEL reduced the reactive output approximately 15 seconds after the initial event. MEL parameters vary among generating units. However, variations in these parameters are not expected to affect the maximum current or the final current. This is because the MEL is set to allow full field-forcing for a period of time within the generator short-time capability, and to reduce the reactive output to a final value with the generator steady-state capability.

The results for the simulation are presented in Table 4. The pre-event and maximum currents are similar to the results obtained in the ETAP analysis. Differences in current on the high-voltage side of the UAT are a result of the different generator terminal voltages. The table lists the pre-event and maximum load current on each bus, and also lists the current at four discrete times (1 s, 5 s, 10 s, and 20 s) after the initial event. The maximum current is observed approximately 0.4 s after the initial event. The current is listed in kA in the top half of the table and as a percentage difference from the pre-event current in the bottom half. The simulation demonstrates that the maximum load current is in the range from 4.8 to 10.0% higher than the pre-event load current. The load current begins to drop from the maximum value within 1 s of the initial event. The final current after MEL operation is in the range from 2.2 to 5.4% higher than the pre-event current.

Table 4. PSS®E Study 1 at 85% Transmission Voltage with Original UAT Loading						
Auxiliaries	**Pre-Event**	**Max**	**1 s**	**5 s**	**10 s**	**20 s**
UAT 2-1 HS kA	0.805	0.874	0.846	0.818	0.817	0.831
2A1 kA (7 kV)	1.256	1.349	1.326	1.279	1.276	1.305
2B1 kA (4 kV)	2.016	2.120	2.093	2.038	2.034	2.066
UAT 2-2 HS kA	0.918	1.006	0.972	0.936	0.932	0.957
2A2 kA (7 kV)	1.523	1.675	1.638	1.562	1.555	1.606
Composite 2B2 , 12B2 (4 kV)	2.179	2.283	2.256	2.199	2.195	2.228
Auxiliaries		**% Max**	**% 1 s**	**% 5 s**	**% 10 s**	**% 20 s**
UAT 2-1 HS kA		8.3	4.8	1.6	1.5	3.1
2A1 kA (7 kV)		7.6	5.7	1.8	1.6	3.9
2B1 kA (4 kV)		5.3	3.8	1.1	0.9	2.5
UAT 2-2 HS kA		9.6	5.9	2.0	1.5	4.2
2A2 kA (7 kV)		10.0	7.6	2.6	2.1	5.4
Composite 2B2 , 12B2 (4 kV)		4.8	3.5	0.9	0.7	2.2

Similar to the ETAP analysis, a second simulation was run using 90% large motor load on each bus. As expected, these simulations resulted in high loader current than Study 1. Results for the second simulation are presented in Table 5. In the second study the maximum current on each load bus is in the range from 9.6 to 13.4% above the pre-event current and the final current is in the range from 5.1 to 7.4% above the pre-event current.

Table 5. ETAP Study 2 at 85% Transmission Voltage with Higher Inductive UAT Loading						
Auxiliaries	**Pre-Event**	**Max**	**1 s**	**5 s**	**10 s**	**20 s**
UAT 2-1 HS kA	0.798	0.909	0.871	0.823	0.819	0.849
2A1 kA (7 kV)	1.240	1.396	1.358	1.282	1.274	1.328
2B1 kA (4 kV)	2.054	2.266	2.210	2.106	2.096	2.167
UAT 2-2 HS kA	0.913	1.042	0.999	0.942	0.935	0.975
2A2 kA (7 kV)	1.518	1.722	1.672	1.571	1.561	1.631
Composite 2B2 , 12B2 (4 kV)	2.230	2.445	2.392	2.282	2.275	2.344
Auxiliaries		**% Max**	**% 1 s**	**% 5 s**	**% 10 s**	**% 20 s**
UAT 2-1 HS kA		13.9	9.1	3.1	3.6	6.4
2A1 kA (7 kV)		12.6	9.5	3.4	2.7	7.1
2B1 kA (4 kV)		10.3	7.6	2.5	2.0	5.5
UAT 2-2 HS kA		14.1	9.4	3.2	2.4	6.8
2A2 kA (7 kV)		13.4	10.1	3.5	2.8	7.4
Composite 2B2 , 12B2 (4 kV)		9.6	7.3	2.3	2.0	5.1

During the event modeled in ETAP, the actual plant output was lower than reported full load output; therefore, increases in UAT loading would occur at reported full load. A sensitivity analysis was performed in PSS®E to model higher station service load. In this assessment the load was increased proportionally until the load on one of the UAT windings was equal to the winding rating – an increase of approximately 34% on UAT2-1 and 10% on UAT2-2. In these cases the load current is proportionately higher; however, the observed increases in current are not significantly different. The base model with 70-80 % motor load exhibited load current increases in the range from 5.1 to 10.0% (compared to 4.8 to 10.0%) and the higher inductive load model with 90% motor load exhibited load current increases in the range from 10.1 to 13.6% (compared to 9.6 to 13.4%).Thus, if the actual plant had been at full load, the expected incremental increases in UAT loading during such an event would be of the same magnitude as for the actual event modeled.

Analysis of NERC GADS Data

The NERC Generating Availability Data System (GADS) contains outage data for generating stations across North America. Outages were analyzed for UATs and other station service transformers with primary winding voltage of 4.16 kV and 480 V. This analysis included 217 UAT outages, 28 outages of 4.16 kV transformers, and 49 outages of 480 V transformers. The cause codes do not provide adequate granularity to determine why the transformers tripped; however, approximately 85% of the outage entries included descriptive comments. The majority of UAT outages with descriptions were scheduled, approximately one-half of the 4.16 kV transformer outages were scheduled and one-half forced, and the majority of 480 V transformer outages were forced.

The descriptions for the forced outages include issues such as transformer failure, overheated transformer or associated equipment, auxiliary power transfer problems, breaker failure, failure of equipment supplied by the transformer (e.g., induced draft fan), problems with transformer outlet leads, current transformer ground, and differential relay operation. Four event descriptions identify improper or incorrect relay settings – one event on a 480 V transformer was for a ground fault for which PRC-025-1 would not be applicable; three events on a 4.16 kV transformer appear to be related to the same relay setting with no other information. While not definitive, there is nothing in the GADS data to suggest that any generating unit outages occurred due to UAT or other station service transformer relay loadability issues during a depressed voltage condition.

Conclusion

Many of the plant auxiliaries (e.g., 4 kV and 7 kV) have a ±10% voltage operating range with most operating above the nominal; such an operating range allows for increased current during lower voltages. Industry practice is to set plant auxiliary relays on the low-voltage side of the UAT to account for a depressed voltage according to equipment ratings. These relays are generally set with a 10 to 15% margin above the expected lower voltage range of the equipment rating. Relays on the low-voltage side of the UAT are also set to account for the starting of large plant auxiliary motors which depresses voltage. The margin in the relay settings accounts for measuring inaccuracy in current transformers and relays, and other uncertainties associated with the equipment and operating conditions.

The maximum current deviations observed in these simulations would be under or marginally above the current threshold (pickup setting) at which the relays on the low-voltage side of the UAT would begin to operate. These relays operate with an inverse-time characteristic such that an overcurrent condition marginally above the pick-up setting must persist for several seconds before the relay will assert a trip output. In these simulations the maximum motor load duration is short in comparison to the operating time of the relay when current is marginally above pickup, and the load current settles to a value below the pickup setting allowing the relay to reset.

Based on a comparison of the simulation models and the actual event data, the simulation results are conservative. The model results, coupled with the GADS analysis, are indicative that a reliability gap does not result from excluding relays on the low-voltage side of the UAT from PRC-025-1. However, industry practice may vary and the conservatism in the model does not fully offset the potential inaccuracies and uncertainties in the relay setting. Thus, while indicative that a reliability gap does not result, this analysis is not definitive.

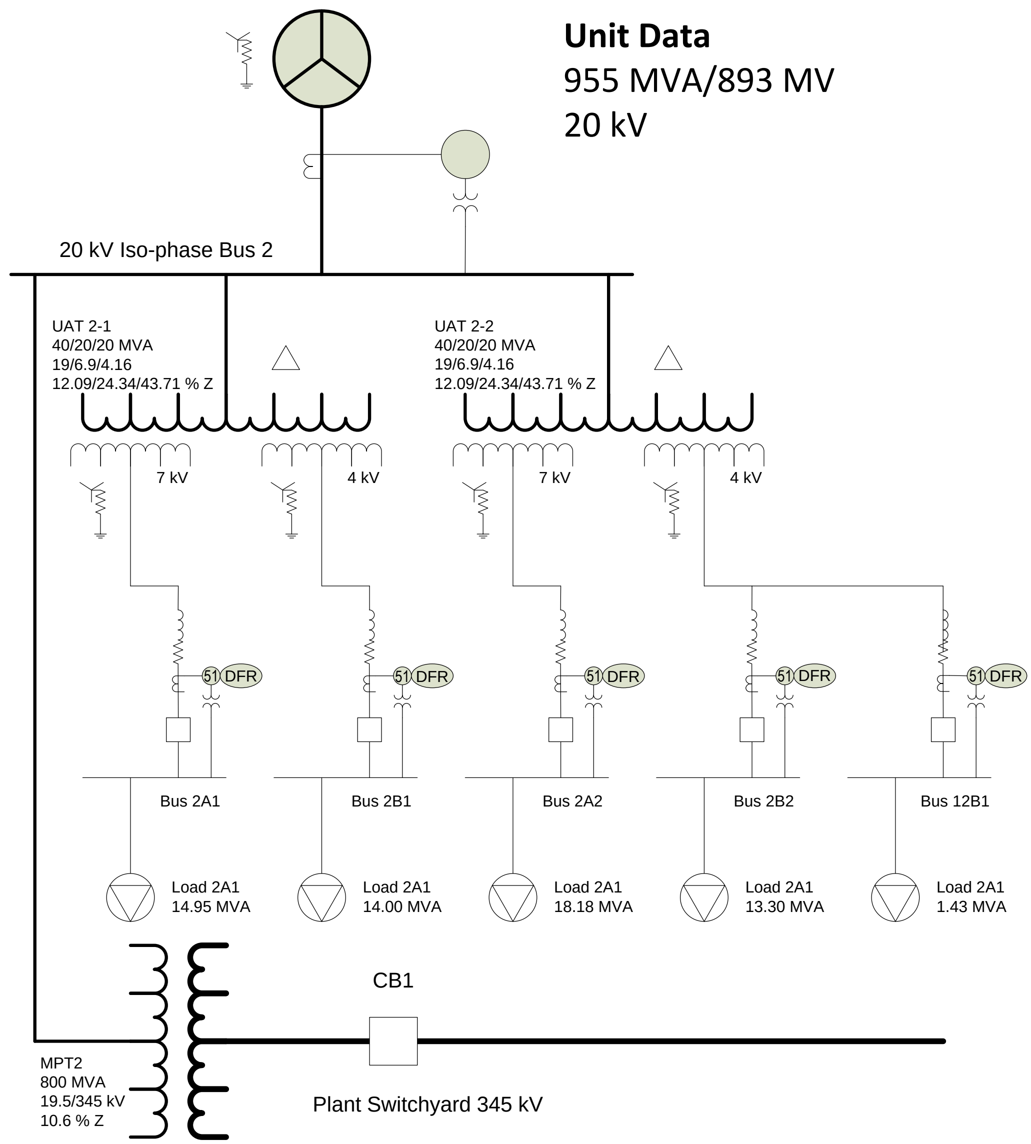
Recommendation

The study using both DFR event data and simulation, and the GADS data analysis, revealed there is not a material gap in reliability; therefore, the recommendation is not to include the low-voltage side relays in the PRC-025-1 standard.

Furthermore, the standard drafting team recognizes that the goal of PRC-025-1 is to prevent the unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment. Since the study revealed that increased loading of the low-side UAT protective relays may reach margins generally employed by industry, other preemptive steps may be desirable. If so, the standard drafting team recommends to NERC a tiered approach to further address this risk.

1. <u>Monitoring</u> – Investigate the feasibility to revise or append the NERC GADS cause codes with greater granularity to facilitate the monitoring and tracking of the UAT, for both load-responsive high-side and low-side protective relay(s) that cause the loss of generation due to a depressed voltage as anticipated by the PRC-025-1 standard.
2. <u>Guideline</u> – Solicit industry input through the appropriate NERC committee for establishing a guideline for setting load-responsive UAT low-side overload protective relays to account for increased loading during depressed voltages. This guideline should be based on information revealed through monitoring that demonstrates a need for industry guidance and not a reliability standard. This option is next if monitoring is not feasible.
3. <u>Standard</u> – Revise the PRC-025-1 standard or create a new standard to address the loadability of the load-responsive UAT high-side and low-side protective relays if lessons learned through monitoring and/or developed guidance do not demonstrate the necessary reliability described in the standard.

Appendix



Unit Data
955 MVA/893 MV
20 kV
20 kV Iso-phase Bus 2
UAT 2-1
40/20/20 MVA
19/6.9/4.16
12.09/24.34/43.71 % Z
UAT 2-2
40/20/20 MVA
19/6.9/4.16
12.09/24.34/43.71 % Z
7 kV
4 kV
7 kV
4 kV
51 DFR
51 DFR
51 DFR
51 DFR
51 DFR
Bus 2A1
Bus 2B1
Bus 2A2
Bus 2B2
Bus 12B1
Load 2A1
14.95 MVA
Load 2A1
14.00 MVA
Load 2A1
18.18 MVA
Load 2A1
13.30 MVA
Load 2A1
1.43 MVA
CB1
MPT2
800 MVA
19.5/345 kV
10.6 % Z
Plant Switchyard 345 kV