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 1: Relay Loadability Evaluation Criteria~~				
~~Application~~	**~~Relay Type~~**	**~~Option~~**	**~~Bus Voltage~~**[5]	**~~Pickup Setting Criteria~~**
		~~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~~		
~~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~~	~~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~~				