Exhibit A

Proposed PRC-023-2 Reliability Standard submitted for approval (Clean and Redline)

A. Introduction

1. **Title: Transmission Relay Loadability**

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

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 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

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 below100 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
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]

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	Effective Date: Jurisdictions where No Regulatory Approval is Required
	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
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	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

Requirement	Applicability	Effective Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
		which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	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
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

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.
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.

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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 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 per application of Attachment B, including identification of the first calendar year in which any criterion in 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 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

- 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 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. OR

Requirement	Lower	Moderate	High	Severe
				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 than 15 months and less than 24 months lapsed between assessments.	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 months or more lapsed between assessments.	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. OR The Planning Coordinator used the criteria established within

Requirement	Lower	Moderate	High	Severe
		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. (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 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)	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 6.1 but failed to provide the list of circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its

Requirement	Lower	Moderate	High	Severe
				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	April 19, 2010	Filed for approval 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)

PRC-023 — 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 — 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.

A. Introduction

1. **Title: Transmission Relay Loadability**

2. **Number:** PRC-023-~~1~~2

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.~~4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to ~~facilities~~circuits defined ~~below:~~ 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

4.2. Circuits

4.2.1 Circuits Subject to Requirements R1 – R5

~~4.1.1~~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 ~~as designated~~selected by the Planning Coordinator ~~as critical to the reliability~~in accordance with R6.

~~4.1.2~~4.2.1.3 Transmission lines operated below 100 kV that are part of the ~~Bulk Electric System.~~BES and selected by the Planning Coordinator in accordance with R6.

~~4.1.3~~4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

~~4.1.4~~4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV ~~as designated~~selected by the Planning Coordinator ~~as critical to the reliability of the Bulk Electric System~~in accordance with R6.

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

~~**4.3.** Distribution Providers with load-responsive phase protection systems as described in Attachment A, applied according to facilities defined in 4.1.1 through 4.1.4., provided~~low voltage terminals connected below 100 kV that ~~those facilities have bi-directional flow capabilities.~~

~~**4.4.** Planning Coordinators.~~

~~**5. Effective Dates[1]: TBD**~~

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

~~**5.1.1** For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) — the beginning~~are part of the ~~first calendar quarter following applicable regulatory approvals.~~

~~**5.1.2** For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals.~~

~~5.1.3~~4.2.1.6 ~~Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified~~BES and selected by ~~its~~the Planning Coordinator ~~pursuant to R3.3 to comply with R1 (including all sub-requirements) for each facility that is added to the Planning Coordinator's critical facilities list determined pursuant to R3.1~~in accordance with R6.

4.2.2 Circuits Subject to Requirement ~~3: 18 months~~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 below100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES

5. Effective Dates

~~**5.2.**~~ 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 ~~applicable regulatory approvals.~~table:

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	First day of the first calendar quarter 12	First day of the first calendar quarter 12

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

Requirement	Applicability	Effective Date: Jurisdictions where Regulatory Approval is Required	Effective Date: Jurisdictions where No Regulatory Approval is Required
	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	months after applicable regulatory approvals	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[2]
	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	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

2 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	Effective Date: Jurisdictions where No Regulatory Approval is Required
		which any criterion in Attachment B applies, unless the Planning Coordinator removes the circuit from the list before the applicable effective date	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
R4	Each Transmission Owner, Generator Owner, and Distribution Provider that	First day of the first calendar quarter six	First day of the first calendar quarter six

Requirement	Applicability	Effective Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
	chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability	months after applicable regulatory approvals	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

B. **Requirements**

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

Criteria:

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

~~R1.2.~~2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating[3] of a circuit (expressed in amperes).

~~R1.3.~~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:

- ~~1.3.1~~ An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
- ~~1.3.2~~ An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

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

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

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

~~R1.6.~~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.

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

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

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

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

~~R1.10.~~10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that ~~they~~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[4].

~~R1.11.~~11. For transformer overload protection relays that do not comply with ~~R1.~~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~~. The protection must allow this overload~~, for at least 15 minutes to ~~allow~~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~~. The setting should be~~ set no less than 100° C for the top oil ~~or~~temperature or no less than 140° C for the winding hot spot temperature[5].

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

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

[4] 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

[5] IEEE standard C57.~~115, Table 3, specifies~~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.

~~**R1.12.2.**~~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.

~~**R1.12.3.**~~c. Include a relay setting component of 87% of the current calculated in Requirement R1~~.~~, criterion 12~~.2~~ in the Facility Rating determination for the circuit.

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

R2. ~~The~~Each Transmission Owner, Generator Owner, ~~or~~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]*

~~**R2.**~~**R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in ~~R1.~~Requirement R1, criterion 6, ~~R1.~~7, ~~R1.~~8, ~~R1.~~9, ~~R1.~~12, or ~~R1.~~13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

~~**R3.**~~**R4.** ~~The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV~~Each Transmission Owner, Generator Owner, and Distribution Provider that ~~must meet~~chooses to use Requirement ~~1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission~~ 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: ~~Medium~~Lower] [Time Horizon: Long Term Planning]*

R5. ~~The~~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]*

~~**1.1**~~ Each Planning Coordinator shall ~~have a process~~conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in Attachment B to determine the ~~facilities that are critical to the reliability of the Bulk Electric System.~~

~~**1.3.1** This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.~~

~~**1.2**~~ ~~The~~circuits in its Planning Coordinator ~~shall maintain a current list of facilities determined according to the process described in R3.1.~~

R6. ~~The~~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 ~~Coordinator shall provide a list of facilities to its~~]*

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

~~R3.3.~~6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within ~~30~~its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to ~~the~~that list.

C. Measures

M1. ~~The~~Each Transmission Owner, Generator Owner, and Distribution Provider shall ~~each~~ have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays ~~are~~is set according to one of the criteria in ~~R1.~~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~~.13. (~~)

~~M1.~~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)

~~M2.~~M3. ~~The~~Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to ~~the criteria in~~Requirement R1~~.~~, criterion 6, ~~R1.~~7, ~~R1.~~8, ~~R1.~~9, ~~R1.~~12, or ~~R.~~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. (~~R2~~R3)

M4. ~~The~~ 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 ~~shall have~~, 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 ~~documented process for the determination of facilities as described in R3~~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)

~~M3.~~M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it 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 as described in Requirement R6. The Planning Coordinator shall have a ~~current~~dated list of such ~~facilities~~circuits and shall have evidence such as dated correspondence that it provided the list to the ~~approriate~~Regional Entities, Reliability

Coordinators, Transmission ~~Operators~~Owners, Generator ~~Operators~~Owners, and Distribution Providers~~. (R3)~~ within its Planning Coordinator area within the required timeframe.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

~~1.1.1~~• For entities that do not work for the Regional Entity, the Regional Entity shall serve as the Compliance Enforcement Authority.

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

~~One calendar year.~~

- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

~~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 ~~R3~~R6. The Planning Coordinator shall retain the most recent list of ~~facilities that are critical to~~ circuits in its Planning Coordinator area for which applicable entities must comply with the ~~reliability of the electric system~~standard, as determined per ~~R3~~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 shall ~~retain its compliance documentation for three years~~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

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

None.

2. **Violation Severity Levels:**

Requirement	Lower	Moderate	High	Severe
R1	N/A	~~Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but evidence is incomplete or incorrect for one or more of the subrequirements.~~ N/A	N/A	~~Relay settings do not comply with any of the sub requirements R1.1 through R1.13~~ ~~OR~~ ~~Evidence does not exist to support that relay settings comply with one of the criteria in subrequirements R1.1 through R1.13.~~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

Requirement	Lower	Moderate	High	Severe
				per Requirement R1.
~~R2~~R3	~~Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2.~~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. 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.

Requirement	Lower	Moderate	High	Severe
~~R3~~R6	N/A	~~Provided the list of facilities critical~~The Planning Coordinator used the criteria established within Attachment B to determine the ~~reliability of~~circuits in its Planning Coordinator area for which applicable entities must comply with the ~~Bulk Electric System~~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 ~~the appropriate~~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	~~Provided the list of facilities critical~~The Planning Coordinator used the criteria established within Attachment B to determine the ~~reliability of~~circuits in its Planning Coordinator area for which applicable entities must comply with the ~~Bulk Electric System~~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 ~~the appropriate~~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)	~~Does not have a process in place to determine facilities that are critical to the reliability of the Bulk Electric System.~~ 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. OR ~~Does not maintain a current list of facilities critical to the reliability of the Bulk Electric System,~~ ~~OR~~ ~~Did not~~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

Requirement	Lower	Moderate	High	Severe
		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. (part 6.2)		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 6.1 but failed to provide the list of ~~facilities critical to the reliability of the Bulk Electric System to the appropriate~~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, ~~January 9, 2007~~June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/~~~filez/reports.html~~/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	April 19, 2010	Filed for approval 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)

PRC-023 — Attachment A

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

1.1. Phase distance.

1.2. Out-of-step tripping.

1.3. Switch-on-to-fault.

1.4. Overcurrent relays.

1.5. Communications aided protection schemes including but not limited to:

1.5.1 Permissive overreach transfer trip (POTT).

1.5.2 Permissive under-reach transfer trip (PUTT).

1.5.3 Directional comparison blocking (DCB).

1.5.4 Directional comparison unblocking (DCUB).

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

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.

~~**3.**~~**2.** The following protection systems are excluded from requirements of this standard:

~~**3.1.**~~**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

~~**3.2.**~~**2.2.** Protection systems intended for the detection of ground fault conditions.

~~**3.3.**~~**2.3.** Protection systems intended for protection during stable power swings.

~~**3.4.**~~**2.4.** Generator protection relays that are susceptible to load.

~~**3.5.**~~**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.

~~**3.6.**~~**2.6.** Protection systems that are designed only to respond in time periods which allow ~~operators~~ 15 minutes or greater to respond to overload conditions.

~~**3.7.**~~**2.7.** Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

~~**3.8.**~~**2.8.** Relay elements associated with ~~DC~~dc lines.

~~**3.9.**~~**2.9.** Relay elements associated with ~~DC~~dc converter transformers.

PRC-023 — 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[6] 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.

[6] 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.

Exhibit B

Implementation Plan for PRC-023-2 submitted for approval

Implementation Plan for PRC-023-2: Transmission Relay Loadability

Standards Involved

- PRC-023-2 —Transmission Relay Loadability

Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before the Transmission Relay Loadability standard can be implemented.

Proposed 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
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	Later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011[1]

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
		of the first calendar quarter 39 months following applicable regulatory approvals of PRC-023-1 (October 1, 2013)	
	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
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	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

Requirement	Applicability	Effective Date	
		Jurisdictions where Regulatory Approval is Required	Jurisdictions where No Regulatory Approval is Required
		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	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
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

1. Applicability

1.1. Requirements within the proposed standard apply to the following:

1.1.1. Functional Entity

1.1.1.1. 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).

1.1.1.2. 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).

1.1.1.3. 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.

1.1.1.4. Planning Coordinators

1.1.2. Circuits

1.1.2.1. Circuits Subject to Requirements R1 – R5

1.1.2.1.1. Transmission lines operated at 200 kV and above

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

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

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

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

1.1.2.1.6. 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

1.1.2.2. Circuits Subject to Requirement R6

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

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

1.2. Other entities may be recipients of data as described in this standard, but have no requirements placed upon them

2. Implementation Dates

For circuits already identified and subject to the requirements in PRC-023-1, the existing implementation dates will remain in effect.

3. Retired Standards

Requirement R1 of PRC-023-1 is retired the first day of the first calendar quarter after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first calendar quarter after Board of Trustees adoption.

Requirement R2 of PRC-023-1 is retired the first day of the first calendar quarter after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

Requirement R3 of PRC-023-1 is retired the first day of the first calendar quarter 18 months after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 18 months after Board of Trustees adoption.

When all requirements of PRC-023-2 become effective in all jurisdictions as specified above, PRC-023-1 — Transmission Relay Loadability will be retired.

Exhibit C

Standard Drafting Team Roster for Project 2010-13 Relay Loadability Order 733

Project 2010-13 Relay Loadability Order 733

Phase I Drafting Team and Blue Ribbon Panel for PRC-023-2

Name and Title Affiliation Contact Info	Bio
Charles W. Rogers Principal Engineer **Drafting Team Chair** Consumers Energy 1945 W. Parnall Road Jackson, Michigan 49201 (517) 788-0027 cwrogers@cmsenergy.com	Charles Rogers is a Principal Engineer at Consumers Energy, where he has been employed since 1978. For the bulk of his career, Charles has been responsible for application of protective relaying to the transmission and distribution systems, and is currently responsible for managing compliance to NERC Standards for the "wires" portion of Consumers Energy. He chaired the NERC System Protection and Control Task Force from its inception in 2004 through May 2008, and continues to be a member of its successor group, the NERC System Protection and Control Task Force. He chaired the ECAR investigation into the August 2003 blackout, chaired the ECAR Protection Panel for several years, and now chairs the RFC Protection Subcommittee. At NERC, he was a member of the "Phase II Standard Drafting Team" in 2005-2006, chaired the standard drafting team that developed PRC-023-1, and currently chairs the standard drafting teams assigned to Projects 2007-17 (Protection System maintenance) and 2010-13 (addressing FERC Order 733). At RFC, he also chaired the standard drafting team that developed PRC-002-RFC-01 and currently chairs a standard drafting team that is developing a regional standard addressing Special Protection Systems. Charles is also a member of IEEE Standards Coordinating Committee 21, and was a key member of the working groups that developed IEEE 1547, IEEE 1547.2, and IEEE 1547.4. He received his BSEE degree from Michigan Technological University in 1978. He is a registered professional engineer in the State of Michigan, and is a Senior Member of IEEE.
Baj Agrawal Engineering Manager Arizona Public Service Co. 2124 W. Cheryl Drive Phoenix, AZ 85021 602-371-6386 bajarang.agrawal@aps.com	Dr. Baj L. Agrawal: Ph.D., University of Arizona, Tucson. Dr. Agrawal is Engineering Manager at Arizona Public Service Co., where he has worked since 1974. He has extensive experience in the analysis, control and testing of subsynchronous resonance, power system dynamics modeling and simulation, and field testing of generators. He has co-authored many papers on subsynchronous resonance analysis and power system testing and has co-authored a book on subsynchronous resonance. Dr. Agrawal is an IEEE fellow and is a registered professional engineer.
David Angell Manager, Delivery Planning Idaho Power Company P.O. Box 70 Boise, Idaho 83707 (208) 388-2701 DaveAngell@idahopower.com	David is the Manager of Delivery Planning for Idaho Power and an Adjunct Professor at Boise State University. He graduated from the University of Idaho with a Bachelor of Science degree in electrical engineering in 1984 and followed with a Master of Science degree in 1986. He has twenty five years of experience in communications, metering, planning, and system protection with Idaho Power and the Bonneville Power Administration.
Gary T. Brownfield Supervising Engineer, Transmission Planning Ameren Services 1901 Chouteau Avenue MC 691 St. Louis, MO 63166-6149 314-554-2556 GBrownfield@ ameren.com	Gary Brownfield is the Supervising Engineer for the Transmission Planning group at Ameren. He has 36 years of engineering experience in the electric utility industry. His work experience encompasses transmission expansion planning, NERC standards compliance, generator interconnection planning, reactive planning, distribution planning, FIDVR, transient stability, events analyses, lightning and switching surges, power system harmonics, power quality, geomagnetic disturbances, and system optimization. He presently serves on the NERC Transmission Issues Subcommittee and the SERC Engineering Committee. He received BSEE and MSEE degrees from the University of Missouri. He is a registered professional engineer and is a Senior Member of IEEE.

Larry Brusseau Principal Engineer/Compliance Program Manager MAPPCOR 1970 Oakcrest Ave. Suite 200 Roseville, MN 55113 (651)294-7077 Le.brusseau@mappcor.org	Mr. Brusseau has over 20 years of experience in the electric power industry. Mr. Brusseau joined MAPPCOR staff in January, 2009 and currently holds the position of Principal Engineer. He is the Compliance Program Manager for MAPPCOR and secretary to the Mid-Continent Compliance Forum. He is also responsible for the Transmission Reliability Assessment Working Group, Northern MAPP Operating Review Working Group and the Missouri Basin Subregional Planning Group; which produces the annual MAPP System Performance Assessment, MAPP Member Reliability Criteria and Study Procedures Manual, and provides input to the MAPP Regional Transmission Plan. He is a subject matter expert for MAPPCOR in transmission planning activities, and regional reliability standards, compliance and enforcement. Prior to joining MAPPCOR, Mr. Brusseau was Midwest Reliability Organization's Standards Manager. In this role, Mr. Brusseau was responsible for assuring that the standards process was being followed properly and those standards in development increased reliability for the region, and was also responsible for the MRO Compliance Data Management System (CDMS) and the Reliability Standard Voting Process (RSVP) systems, he worked with MRO's Standards Committee, NERC Standards Review Subcommittee, Regional Standards Drafting Teams, and NERC Standards Drafting Teams. He has participated in over 50 Compliance Audits and Readiness Evaluations. From 1989 - 2005 he worked for MAPP producing the annual MAPP Operating and Planning Stability model, overseeing the production of the MAPP Operating and Planning Power Flow models, and was responsible for maintaining MAPP's Model Building Process. He also conducted transient, voltage and small signal stability studies of the MAPP system as well as other special studies involving system security. He was chair of NERC's Multiregional Modeling Working Group (MMWG) and System Dynamics Database Working Group (SDDWG). Mr. Brusseau received a BSEE degree from North Dakota State University in 1989 and is a member of the IEEE Power & Energy Society.
W. Mark Carpenter VP and Chief Technology Officer Oncor 2509 Douglas Avenue Irving, Texas 75062 (214) 486-3588 mark.carpenter@ oncor.com	Mark joined Texas Power and Light Company as a summer engineering intern in 1972 and became a permanent employee in 1975 upon completion of his BS Electrical Engineering degree from Texas Technological University. Mark has held various field management and engineering management positions in T&D, primarily in the transmission and substation area of Oncor and its predecessor companies. These include Distribution Superintendent, Transmission Superintendent, Substation Engineering Manager, Director of System Protection, Director of Engineering, and Vice President and Chief Information Officer. Mark is currently serving as Vice President and Chief Technology Officer. In this role, he leads Oncor’s technology vision, strategic planning, R&D efforts, and technology implementation. Mark’s protective relaying background is extensive and includes active participation in the IEEE Power System Relaying Committee as the past Line Protection Subcommittee Chair and Working Group Chair for the original version of the Transmission Line Protection Guide and the Guide for Transmission Protective Relaying Performance Measuring Methodology that formed the basis for system protection performance measurements. He is a member of the Texas Society of Professional Engineers and is a registered Professional Engineer in the State of Texas.
Jay Caspary Director, Transmission Development Southwest Power Pool 415 North McKinley Suite 400 Little Rock, AR 72205 (501) 614-3220 jcaspary@spp.org	As Director of Transmission Development at Southwest Power Pool, Jay is charged with addressing emerging, strategic and ongoing transmission issues with a primary focus on removing barriers to effective coordinated expansion planning beyond traditional seams. Recent initiatives to get the best lines in the best corridors include investigations into mechanisms and incentives to enable rightsizing key facilities in critical ROWs with due consideration of land use and environmental impacts. Jay has almost 30 years of experience in transmission planning, electric and gas resource planning, regulatory services/pricing, marketing/customer choice, and transmission services. Jay joined SPP in 2001 after a 19-year career at Illinois Power/Dynegy. Jay has been instrumental in developing effective transmission expansion plans for SPP, as well as collaborative long-range planning with SPP’s neighbors including ERCOT, MISO, TVA, and others. Jay has and continues to serve on several industry committees including NERC’s Intermittent and Variable Generation Task Force, EPRI’s Grid Operations, Planning & Renewable Integration program and the DOE’s Eastern Interconnection Planning Collaborative. Jay has served on the Board of Directors of the Utility Wind Integration Group since 2006. Jay graduated from the University of Illinois-Urbana with a Bachelor of Science degree in Electrical Engineering and has completed course requirements for a Master of Engineering Degree from Iowa State University.

Kenneth A. Donohoo P.E. Oncor Electric Delivery Company LLC 2233 B Mountain Creek Parkway Dallas, TX 75211 (214)743-6823 kdonoho1@oncor.com	Ken Donohoo joined Oncor Electric Delivery in May 2007 as Director System Planning. His team administers distribution and transmission planning analysis including steady state, dynamic analysis (voltage and transient), harmonic analysis, generation interconnection or change request studies, NERC support/reporting, regulatory support, planning reports and collection/development of power system planning data. Ken has 28 years of related experience in increasingly complex supervisory/management positions, including significant experience in transmission planning analysis, system operations and resource planning. He received a Bachelor of Science Electrical Engineering (BSEE) degree from the University of Texas at Arlington in 1982. His extensive background includes engineering budget analysis, transmission planning, transient analysis, EMTP analysis, insulation coordination, surge arrester application, switching analysis, wheeling impact, loss analysis, project management, and engineering management. He is a registered professional engineer in the state of Texas. He is a senior member of Institute of Electrical and Electronics Engineers (IEEE), active in the Utility Wind Integration Group (UWIG), serves on the North American Electric Reliability Council Planning Committee Transmission Issues Subcommittee (TIS), active in the ERCOT Regional Planning Group and is Chairperson of the ERCOT TAC Reliability Operating Subcommittee.
Jim Griffith Manager, System Operations Southern Company Services P.O. Box 2641 Birmingham, AL 35202 (205) 257-6892 jsgriffi@southernco.com	Jim Griffith has over 38 years experience at Southern Company. He has worked in power system (PMS) management application development, operations planning, real time operations both at the transmission switching level and the Bulk Power Operations level. These include managing application development groups in the Southern Company PMS application department which were responsible for developing and installing System Control, System Security, and Operations Planning applications (AGC, State Estimation, Unit commitment, etc.) for Southern Company. From there Jim moved to manage the Operations Planning section for the Bulk Power Operations Power Coordination Center for Southern Company. He later moved to Alabama Power Company Transmission Control Center where he was responsible for operations planning and operator training. Jim currently is manager of real time system operations at the Bulk Power Operations Power Coordination Center (PCC) for Southern Company. The PCC is responsible for the generation and load balancing for the Southern Control Area, for interchange scheduling, and for transmission security, including the Security Coordinator function. Jim has served in numerous roles in the power industry throughout his career. He has held numerous positions in NERC and SERC with responsibilities such as: leading the Security Process Support Systems Task Force, serving on the IDC Working group, the Functional Model Working Group, as well as various tagging committees and special project committees. He has represented various entities on the NERC OC such as being the Investor – Owned Utility group, SERC region representative, etc. Jim has been on the NERC region SERC Operating Committee for over twelve years representing Southern Company and serving as vice chair and chair as well as leading other SERC subcommittees to accomplish specific tasks. Jim has a BS degree from Mississippi State University.
Bill Harm Sr. Consultant PJM HARM@pjm.com	Bill Harm has over 35 years of industry experience with PJM through various assignments involving real time operation, operations planning, and transmission planning. Mr. Harm's current responsibilities involve performance assessment, and policy development responsibilities. He either has or continues to represent PJM in various industry forums and groups, including RFC, NERC, and the ISO/RTO forums. He earned a Bachelor and Maters of Science Degree in Electrical Engineering from Drexel University and is a registered professional Engineer Commonwealth of Pa.
Jim Ingleson Senior Power System Engineer RLC Engineering LLC 402 Bond Road Altamont, NY 12009 518-861-6269 jim.ingleson@rlc-eng.com	Jim Ingleson is a Senior Power System Engineer with RLC Engineering LLC, specializing in system protection. Previously Jim has worked for General Electric Company, New York Power Pool, and New York ISO. He received the 2007 IEEE PES Distinguished Service Award for career service to the Power System Relay Committee, and is a past Chair of the NPCC Task Force on System Protection. Jim holds B.S. and M. Eng. Degrees in Electric Power Engineering from RPI. His years of service to the electric utility industry total over 42. Mr. Ingleson is a licensed Professional Engineer in MA and NY, and a Senior Member of the IEEE.

Takis Laios Manager Projects American Electric Power 700 Morrison Road Gahanna, OH 43230-6642 (614) 552-1664 tlaios@aep.com	Takis Laios has over 30 years of industry experience with AEP through various assignments involving transmission planning, performance assessment, and policy development responsibilities. He either has or continues to represent AEP in various industry forums and groups, including ECAR, RFC, NERC, and PJM. He earned a Bachelor of Science Degree in Electrical Engineering from Northeastern University, a Master of Engineering Degree in Electric Power Engineering from Rensselaer Polytechnic Institute, and a Masters in Business Administration Degree from The Ohio State University.
John Odom Vice President of Planning and Operations Florida Reliability Coordinating Council, Inc. 1408 N. Westshore Blvd., Suite 1002 Tampa, FL 33607-4512 (813)207-7985 jodom@frcc.com	John Odom is Vice President of Planning and Operations at the Florida Reliability Coordinating Council (FRCC). John joined FRCC in May, 2005 after 26 years at Progress Energy Corporation (PEF). He is responsible for oversight of all Member Services Activities, including the FRCC standing committees, FRCC Reliability Coordinator and Planning Authority function. Additionally, he oversees the Regional Entity functions of reliability assessment, situational awareness, training and certification of system operators, and event analysis. From 2001 – 2007, John was the FRCC Representative on the NERC Reliability Assessment Subcommittee (RAS). John is currently the chair of the Assess Future Transmission Needs Standards Drafting Team (AFTNSDT), which is re-writing the existing TPL-001 through TPL-006.
Chifong Thomas Senior Director, Energy Market and Strategy BrightSource Energy, Inc. 1999 Harrison Street Suite 2150 Oakland, CA 94612 (510) 250-8166 cthomas@ brightsourceenergy.com	Chifong Thomas is the Senior Director, Energy Markets and Strategy at BrightSource Energy, Inc. Prior to her current position, she was a Principal Transmission Planning Engineer at Pacific Gas and Electric Company (PG&E). She has more than 39 years of electric utility experience, more than 37 of which in electric transmission planning. She has both conducted and supervised transmission planning studies to develop plans for PG&E transmission system from 60 kV to 500 kV. She has participated in developing methodologies, policies and strategic plans, and in contract negotiations. Ms Thomas has also served as expert witness in various regulatory and judicial forums. She has served on various technical organizations and work groups, including WECC Technical Studies Subcommittee (where she served as Chair from 2003 to 2005) and various WECC task forces, four NERC Standards Drafting Teams, and Industry Advisory Committees of the California Energy Commission and of EPRI. She currently serves as Secretary of the WECC-Planning Coordination Committee (PCC) and also chairs the WECC PCC-TEPPC Coordination Task Force. She had also served on the Technical Advisory Committee (Electrical Engineering) to California Board of Registration for Professional Engineers and Land Surveyors. Ms Thomas holds a Bachelor of Science Degree in Electrical Engineering from Washington State University and is a registered Electrical Engineer in the State of California. She is also a senior member of the IEEE.
Dana Walters Mgr Transmission Planning, Process & Policy national**grid** 40 Sylvan Road, Waltham, MA 02451 781-907-2501 dana.walters@us.ngrid.com	Dana Walters is a Manager in the Transmission Planning group at National Grid. Mr. Walters has 34 year of experience in the Electric Utility industry. Most of his experience involves various aspects of Transmission Planning. This includes topics such as analytical studies of thermal, stability, short circuit, generator interconnections, and lightning protection. Other areas of experience include involvement in Investment Planning, tariff design, Consulting, Production Cost analysis, and Distribution Planning. In his role as a Transmission Planner, Mr. Walters has been involved in numerous committees and working groups at the NERC, NPCC, and ISO levels. Mr. Walters has a Masters in Engineering Management from Northeastern University and a Bachelor in Electrical Engineering with a focus in Power Systems also from Northeastern University. Mr. Walters is a registered professional engineer in New Hampshire and is a member of IEEE.
Philip B. Winston Chief Engineer Southern Company Transmission 62 Like Mirror Road Bin # 50061 Forest Park, Georgia 30297 (404) 608-5989 pbwinsto@southernco.com	Philip Winston is presently the Chief Engineer, Protection and Control for Southern Company Transmission. Previously he was the Manager, Protection and Control Applications with Georgia Power Company for 20 years. With over 37 years experience in Protection, Operations, and Engineering, he is active in Southern Company standardization efforts as well as being involved in regional and national organizations responsible for utility standards and disturbance analysis. He is the past Chairman of the IEEE/ Power System Relaying Committee and past Chair of the PSRC Systems Protection and the Line Protection Subcommittees. He serves on the NERC SPCS, and several NERC Standard Drafting Teams. He holds a BSEE from Clemson University, a MSEE from Georgia Tech, and is a registered Professional Engineer in the State of Georgia.

Eric Allen North American Electric Reliability Corporation 116-390 Village Boulevard Princeton, New Jersey 08540-5721 Eric.Allen@nerc.net	Eric Allen received his B.S. degree in Electrical Engineering from Worcester Polytechnic Institute in 1993 and his S.M. degree in Electrical Engineering from the Massachusetts Institute of Technology in 1995. In 1998 he received the Ph.D. degree in Electrical Engineering from M.I.T. with the thesis titled "Stochastic Unit Commitment in a Deregulated Electric Utility Industry." Eric was employed for more than 7 years as a Senior Engineer in transmission planning at the New York Independent System Operator (NYISO), and is now employed as a Senior Engineer in System Analysis and Reliability Initiatives at the North American Electric Reliability Council (NERC). He has participated extensively in the investigation of the August 14, 2003 blackout. He is a licensed Professional Engineer in New York and participates in the IEEE Power System Dynamic Performance Committee.
Joseph Bucciero President and Executive Consultant **NERC Coordinator** Bucciero Consulting, LLC 3011 Samantha Way Gilbertsville, Pennsylvania 19525 (267) 981-5445 joe.bucciero@gmail.com	Joseph (Joe) Bucciero is the NERC Staff Coordinator for the Relay Loadability Order 733 Drafting Team and the Cyber Security Order 706 Drafting Team. Mr. Bucciero is an electric industry executive with more than 40 years of industry experience that has successfully established his position and reputation as a leader in the industry. He has extensive management, technical, and business development experience in serving the needs of the electric utilities. He has launched his own practice to provide strategic guidance on Smart Grid, interoperability, cyber security, and EMS/SCADA issues to utilities, vendors, and industry groups. He is skilled in project management, and is adept at developing innovative, cost-effective ideas and solutions, and providing engineering and real-time system services that support utility corporate objectives. Mr. Bucciero is a council emeritus member on the US DoE "GridWise Architecture Council", a signatory of the GridWise Interoperability Constitution, and a member of the Cigré Working Group on 21st Century EMS Architectures. He is a founding Board Member of the Institute of Research and Education in Power System Dynamics (IREP), is a Senior Member of IEEE, and holds BSc Mathematics from Villanova University.
Robert W. Cummings Director of System Analysis and Reliability Initiatives **NERC Staff Liaison & Subject Matter Expert** North American Electric Reliability Corporation 116-390 Village Boulevard Princeton, New Jersey 08540-5721 (609) 947-0103 (505) 508-1198 bob.cummings@nerc.net	Mr. Cummings joined NERC in 1996 and has extensive experience in the industry in system planning, operations engineering, and wide area planning. He holds a Bachelor of Science Degree in Power System Engineering from Worcester Polytechnic Institute and is an IEEE Senior Member. His geographically diverse experience includes Central Vermont Public Service Corporation in System Planning (generation and transmission), Public Service Company of New Mexico, and the East Central Reliability Coordination Agreement (ECAR). Mr. Cummings was the "father" of power interchange transaction "tagging" and the Interchange Distribution Calculator, which shows loading contributions on key system transmission interfaces, or "flowgates," for the Eastern Interconnection. He was intimately involved in the investigation team of the 2003 blackout as a team leader with responsibilities in the sequence of events development, modeling and studies (powerflow and dynamics analysis), and transmission/generation performance areas. He directed the NERC Event Analysis and Information Exchange program for five years. Mr. Cummings was instrumental in the founding of the NERC System Protection and Controls Task Force, now the System Protection and Control Subcommittee (SPCS), acting as the staff coordinator from 2004 through 2009. Mr. Cummings is the staff coordinator for the NERC Transmission Issues Subcommittee and is the technical advocate in the North American Synchro-Phasor Initiative. He is also the technical director of the NERC System Protection and Control Performance Improvement Initiative, the Modeling Improvements Initiative, and the Frequency Response Improvement Initiative.
Philip J Tatro Senior Performance and Analysis Engineer **NERC Staff Advisor & Subject Matter Expert** North American Electric Reliability Corporation 116-390 Village Boulevard Princeton, New Jersey 08540-5721 (609) 452-8060 phil.tatro@nerc.net	Phil Tatro is the NERC staff coordinator for the System Protection Control Subcommittee (SPCS) and has 25 years of industry experience. Prior to joining NERC he worked for 23 years at New England Electric System and National Grid. His experience there included assignments in Protection and Control Engineering, the Québec-New England 2000 MW HVdc interconnection, development of independent transmission projects, and Transmission Planning. During this time he was a member of several NERC, NPCC and New England Power Pool committees, task forces, and standard drafting teams. Phil chaired the NPCC SS-38 Working Group on Inter-Area Dynamic Analysis and the NERC Major System Disturbance Task Force responsible for dynamic simulation of the August 14, 2003 blackout. He received his Bachelor of Science degree, magna cum laude, from Rensselaer Polytechnic Institute in Troy, NY in 1985 and his Master of Engineering degree, also from Rensselaer Polytechnic Institute, in 1986. He is a registered professional engineer in the Commonwealth of Massachusetts and is a member of the IEEE Power & Energy Society.

Exhibit D

Mapping Document for the proposed PRC-023-2 Reliability Standard

PRC-023-2 Mapping of Requirements from PRC-023-1 and Directed Modifications in Order No. 733

Mapping of PRC-023-1 to PRC-023-2	
Requirement in the Existing PRC-023-1	**Location in PRC-023-2**
R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. 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:	Requirement R1
R1.1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes). **R1.2.** Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating2 of a circuit (expressed in amperes). **R1.3.** Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation: **R1.3.1.** An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line. **R1.3.2.** An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance. **R1.4.** Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of: - 115% of the highest emergency rating of the series capacitor. - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance with R1.3, using the full line inductive reactance. **R1.5.** Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes). **R1.6.** Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability. **R1.7.** Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current	Requirements R1.1 through R1.13 are now criteria 1 through 13 under Requirement R1

Mapping of PRC-023-1 to PRC-023-2	
Requirement in the Existing PRC-023-1	**Location in PRC-023-2**
flow from the load to the generation source under any system configuration. **R1.8.** Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration. **R1.9.** Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration. **R1.10.** Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at or below the greater of: - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment. - 115% of the highest operator established emergency transformer rating. **R1.11.** For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following: - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator to take controlled action to relieve the overload. - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100° C for the top oil or 140° C for the winding hot spot temperature3. **R1.12.** When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints: **R1.12.1.** Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer. **R1.12.2.** Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees. **R1.12.3.** Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit. **R1.13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.	
R2. The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.	Requirement R3

Mapping of PRC-023-1 to PRC-023-2	
Requirement in the Existing PRC-023-1	**Location in PRC-023-2**
R3. The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability.	Requirement R6
R3.1. The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System. **R3.1.1.** This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.	Attachment B
R3.2. The Planning Coordinator shall maintain a current list of facilities determined according to the process described in R3.1.	Requirement R6, Part 6.1
R3.3. The Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list.	Requirement R6, Part 6.2

Mapping of Directed Changes in Order No. 733		
Paragraph in Order No. 733	**Text**	**Location in PRC-023-2**
60	With respect to sub-100 kV facilities, we adopt the NOPR proposal and direct the ERO to modify PRC-023-1 to apply an "add in" approach to sub-100 kV facilities that are owned or operated by currently-Registered Entities or entities that become Registered Entities in the future, and are associated with a facility that is included on a critical facilities list defined by the Regional Entity. We also direct that additions to the Regional Entities' critical facility list be tested for their applicability to PRC-023-1 and made subject to the Reliability Standard as appropriate.	Requirement R6 and Attachment B
69	Finally, pursuant to section 215(d)(5) of the FPA, we direct the ERO to modify Requirement R3 of the Reliability Standard to specify the test that planning coordinators must use to determine whether a sub-200 kV facility is critical to the reliability of the Bulk-Power	Requirement R6 and Attachment B

Mapping of Directed Changes in Order No. 733		
Paragraph in Order No. 733	**Text**	**Location in PRC-023-2**
	System. We direct the ERO to file its test, and the results of applying the test to a representative sample of utilities from each of the three Interconnections, for Commission approval no later than one year from the date of this Final Rule.	
97	Finally, commenters argue that there should be some mechanism for entities to challenge criticality determinations. We agree that such a mechanism is appropriate and direct the ERO to develop an appeals process (or point to a process in its existing procedures) and submit it to the Commission no later than one year after the date of this Final Rule.	Addressed in Section 1700 of the NERC Rules of Procedure
186	However, we will adopt the NOPR proposal to direct the ERO to modify PRC-023-1 to require that transmission owners, generator owners, and distribution providers give their transmission operators a list of transmission facilities that implement sub-requirement R1.2.	Requirement R4
203	We adopt the NOPR proposal and direct the ERO to modify sub-requirement R1.10 so that it requires entities to verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with the fault.	Requirement R1, criterion 10, Part 10.1
224	While we are not adopting the NOPR proposal, we direct the ERO to document, subject to audit by the Commission, and to make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant sub-requirement R1.12.	Requirement R5 provides the ERO the data necessary to make available the list of facilities
237	We adopt the NOPR proposal and direct the ERO to modify the Reliability Standard to add the Regional Entity to the list of entities that receive the critical facilities list. [sub-requirement R3.3]	Requirement R6, Part 6.2
244	We adopt the NOPR proposal and direct the ERO to include section 2 of Attachment A in the modified Reliability Standard as an additional Requirement with the appropriate violation risk factor and violation severity level.	Requirement R2
264	After further consideration, and in light of the comments, we will	Attachment A,

Mapping of Directed Changes in Order No. 733		
Paragraph in Order No. 733	**Text**	**Location in PRC-023-2**
	not direct the ERO to remove any exclusion from section 3, except for the exclusion of supervising relay elements in section 3.1. Consequently, we direct the ERO to revise section 1 of Attachment A to include supervising relay elements on the list of relays and protection systems that are specifically subject to the Reliability Standard.	Section 1.6 and Attachment A, Section 2.1
283	Additionally, in light of our directive to the ERO to expand the Reliability Standard's scope to include sub-100 kV facilities that Regional Entities have already identified as necessary to the reliability of the Bulk-Power System through inclusion in the Compliance Registry, we direct the ERO to modify the Reliability Standard to include an implementation plan for sub-100 kV facilities.	Implementation Plan
284	We also direct the ERO to remove the exceptions footnote from the "Effective Dates" section.	Footnote 1 removed from the "Effective Dates: section

Exhibit E

Proposed NERC Rules of Procedure Section 1700 – Challenges to Determinations

PROPOSED NEW SECTION FOR NERC RULES OF PROCEDURE

SECTION 1700 — CHALLENGES TO DETERMINATIONS

1701. Scope of Authority

Section 1700 sets forth the procedures to be followed for Registered Entities to challenge determinations made under various Reliability Standards or terms defined in the Glossary of Terms Used in NERC Reliability Standards.

1702. Challenges to Determinations by Planning Coordinators Under Reliability Standard PRC-023

1. This Section 1702 establishes the procedures to be followed when a Registered Entity wishes to challenge a determination by a Planning Coordinator of the sub-200 kV circuits in its Planning Coordinator area for which Transmission Owners, Generator Owners, and Distribution Providers (defined as "Registered Entities" for purposes of this Section 1702) must comply with the requirements of Reliability Standard PRC-023.

2. Planning Coordinator Procedures

   2.1 Each Planning Coordinator shall establish a procedure for a Registered Entity to submit a written request for an explanation of a determination made by the Planning Coordinator under PRC-023.

   2.2 A Registered Entity shall follow the procedure established by the Planning Coordinator for submitting the request for explanation and must submit any such request within 60 days of receiving the determination under PRC-023 from the Planning Coordinator.

   2.3 Within 30 days of receiving a written request from a Registered Entity, the Planning Coordinator shall provide the Registered Entity with a written explanation of the basis for its determination under PRC-023, unless the Planning Coordinator provided a written explanation of the basis for its determination when it initially informed the Registered Entity of its determination.

3. A Registered Entity may challenge the determination of the Planning Coordinator by filing with the appropriate Regional Entity, with a copy to the Planning Coordinator, within 60 days of receiving the written explanation from the Planning Coordinator. The challenge shall include the following: (a) an explanation of the technical reasons for its disagreement with the Planning Coordinator's determination, along with any supporting documentation, and (b) a copy of the Planning Coordinator's written explanation. Within 30 days of receipt of a challenge, the Planning Coordinator may file a response to the Regional Entity, with a copy to the Registered Entity.

4. The filing of a challenge in good faith shall toll the time period for compliance with PRC-023 with respect to the subject facility until such time as the challenge is withdrawn, settled or resolved.

5. The Regional Entity shall issue its written decision setting forth the basis of its determination within 90 days after it receives the challenge and send copies of the decision to the Registered Entity and the Planning Coordinator. The Regional Entity may convene a meeting of the involved entities and may request additional information. The Regional Entity shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

6. A Planning Coordinator or Registered Entity affected by the decision of the Regional Entity may, within 30 days of the decision, file an appeal with NERC, with copies to the Regional Entity and the Planning Coordinator or Registered Entity. The appeal shall state the basis of the objection to the decision of the Regional Entity and shall include the Regional Entity decision, the written explanation of the Planning Coordinator's determination under PRC-023, and the documents and reasoning filed by the Registered Entity with the Regional Entity in support of its objection. The Regional Entity, Planning Coordinator or Registered Entity may file a response to the appeal within 30 days of the appeal.

7. The NERC Board of Trustees shall appoint a panel to decide appeals from Region Entity decisions under Section 1702.5. The panel, which may contain alternates, shall consist of at least three appointees, one of whom must be a member of the NERC staff, who are knowledgeable about PRC-023 and transmission planning and do not have a direct financial or business interest in the outcome of the appeal. The panel shall decide the appeal within 90 days of receiving the appeal from the decision of the Regional Entity and shall affirm the determination of the Planning Coordinator if it is supported by substantial evidence.

8. The Planning Coordinator or Registered Entity affected by the decision of the panel may request that the NERC Board of Trustees review the decision by filing its request for review and a statement of reasons with NERC's Chief Reliability Officer within 30 days of the panel decision. The Board of Trustees may, in its discretion, decline to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. Within 90 days of the request for review under this Section 1702.8, the NERC Board of Trustees may either: (a) issue a decision on the merits, which shall be the final NERC decision, or (b) issue a notice declining to review the decision of the panel, in which case the decision of the panel shall be the final NERC decision. If no written decision or notice declining review is issued within 90 calendar days, the appeal shall be deemed to have been denied by the NERC

Board of Trustees and this will have the same effect as a notice declining review.

9. The Registered Entity or Planning may appeal the final NERC decision to the applicable governmental authority within 30 days of receipt of the Board of Trustees' final decision or notice declining review, or expiration of the 90-day review period without any action by NERC. .

10. The Planning Coordinator and Registered Entity are encouraged, but not required, to meet to resolve any dispute, including use of mutually agreed to alternative dispute resolution procedures, at any time during the course of the matter. In the event resolution occurs after the filing of a challenge, the Registered Entity and Planning Coordinator shall jointly provide to the applicable Regional Entity a written acknowledgement of withdrawal of the challenge or appeal, including a statement that all outstanding issues have been resolved.

Exhibit F

Development Record of the proposed PRC-023-2 Reliability Standard

Project 2010-13: Relay Loadability Order

Related Files

Status:
The NERC Board of Trustees adopted the standard and implementation plan and approved the VRFs and VSLs at its March 10, 2011 meeting.

Background:
As the ERO, NERC must address all directives in Orders issued by FERC. On March 18, 2010 FERC issued Order No. 733 which approved Reliability Standard PRC-023-1 – Transmission Relay Loadability, and also directed NERC, as the Electric Reliability Organization ("ERO"), to develop certain modifications to the PRC-023-1 standard through its Reliability Standards development process, to be completed by specific deadlines. Attachment 1 to the SAR contains the directives and associated deadlines. The Order also directed development of two new Reliability Standards to address issues related to generator relay loadability and the operation of protective relays due to power swings. The standards-related directives in Order 733 are aimed at closing some reliability-related gaps in the scope of PRC-023-1.

This SAR's scope includes three standard development phases to address the standards-related directives in Order No. 733 directives. Phase I is focused on making the specific modifications to PRC-023-1 that were identified in the order; Phase II is focused on developing a new standard to address generator relay loadability; and Phase III is focused on developing requirements that address protective relay operations due to power swings.

Draft	Action	Dates	Results	Consideration of Comments
Draft PRC-023-2 Clean **(44)** | Redline to last posting **(45)** Redline to last approval **(46)** Implementation Plan Clean **(42)** | Redline to last posting **(43)**	Recirculation Ballot Info **(47)** Vote>>	02/24/11 - 03/07/11	Summary **(49)** Full Record **(48)**	
PRC-023-2 Clean **(32)** | Redline to last posting **(33)** Redline to last approval **(34)** Implementation Plan Clean **(30)** | Redline to last	Successive Ballot Info **(38)** Vote>>	01/24/11 - 02/14/11	Summary **(40)** Full Record **(39)**	Consideration of Comments **(41)**

posting(31) **Supporting Materials** VRF/VSL Justification(29) Mapping Document(28)	Non-Binding Poll Info(35) Vote>>	01/24/11 - 02/13/11	Non-Binding Poll Results(36)	Consideration of Comments(37)
SAR for Relay Loadability clean (18)| Redline to last posting(19) PRC-023-2 Clean (15)| Redline to last posting(16) Redline to last approval(17) Implementation Plan Clean(14) **Supporting Materials:** Comment form (Word)(13)	Intial Ballot Info(24) Vote>>	12/07/10 - 12/16/10 (closed)	Summary(26) Full Record(25)	Consideration of Comments(27)
	Ballot Pool Info(23) Join>>	11/01/10 - 12/02/10 (closed)		
	45-day Formal Comment Period Info(20) Submit Comments>>	11/01/10 – 12/16/10 (closed)	Comments Received(21)	Consideration of Comment(22)
PRC-023- Attachment B(9) **Supporting Materials:** Comment form (Word)(8)	Comment Period Info(10) Submit Comments>>	9/23/10 - 10/12/10 (closed)	Comments Received(11)	Consideration of Comments (12)
Draft 1 SAR for Relay Loadability Modifications and Additions PRC-023-2 Draft SAR Version 1 (4)	Comment Period Info>>(5)	08/19/10 - 09/19/10 (closed)	Comments Received(6)	Consideration of Comments (7)

Supporting Materials: Comment Form (Word) **(3)** PRC-023-2 clean **(1)** | redline **(2)** to last approval	Submit Comments>>			

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Standard Development Roadmap

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

Development Steps Completed:

1. The Standards Committee approved the SAR for posting on August 12, 2010.
2. SAR posted for formal comment on August 19, 2010.
3. Standard posted for informal comment period on August 19, 2010.

Proposed Action Plan and Description of Current Draft:

This is the first draft of the requirements developed to address the FERC directives in Order No. 733 and posted for an informal comment period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop second draft of SAR and respond to comments.	September, 2010 – October, 2010
2. Post the standard for 45-day comment period with concurrent ballot	October , 2010
3. Develop second draft of the standard and respond to comments.	December, 2010 – January, 2011
4. Re-ballot the proposed standard	January, 2011
5. NERC Board approval	February, 2011
6. Submit standard to FERC for approval	March, 2011

A. Introduction

1. **Title: Transmission Relay Loadability**

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

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

4. **Applicability:**

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

   4.1.1 Transmission lines operated at 200 kV and above.

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

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

   4.1.4 Transformers with low voltage terminals connected below 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System (BES).

   The SDT will ensure that 4.1.2 and 4.1.4 are consistent with the applicability methodology once it is developed.

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

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

   4.4. Planning Coordinators.

5. **Effective Dates:**

   5.1. Requirement R1, Requirement R2, Requirement R3, Requirement R4:

   5.1.1 For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) —the beginning of the first calendar quarter following applicable regulatory approvals.

   5.1.2 For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals.

   5.1.3 Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its Planning Coordinator pursuant to Requirement R5, Part 5.3 to comply with Requirement R1 (including all sub-requirements) for each facility that is added to the Planning Coordinator's critical facilities list determined pursuant to Requirement R5, Part 5.1.

   5.2. Requirement R5: 18 months following applicable regulatory approvals.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, Settings1 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, and to prevent its out-of-step blocking schemes from blocking tripping for 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] [Mitigation Time Horizon: Long Term Planning].

Settings:

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, Setting 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 to the under any system configuration.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer such that the protection settings do not expose the limiting piece of equipment to fault level and duration that exceeds its capability and so that the relays do not operate at or below the greater of:

> FERC Order 733, ¶203: Modify sub-requirement R1.10 to verify equipment is capable of sustaining the anticipated overload associated with the fault.

- 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.

11. For transformer overload protection relays that do not comply with Requirement R1, Setting 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[2].

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, Setting 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 that uses a circuit capability with the practical limitations described in Requirement R1, Settings.6,7, 8, 9, 12, or

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

13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 Setting 2 shall provide its Planning Coordinator, Transmission Operator, Regional Entity, and Reliability Coordinator with a list of facilities 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]

FERC Order 733, ¶186: Modify R1.2 to require that TOs, GOs, and DPs give their TOPs a list of transmission facilities that implement R1.2.

R4. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 Setting 12 shall provide a list of the facilities associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]

FERC Order 733, ¶224: Make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant sub-requirement R1.12.of anticipated overload.

R5. Each Planning Coordinator shall apply the criteria in Attachment B to determine which of the facilities (transmission lines operated below 200 kV and transformers with low voltage terminals connected below 200 kV) in its Planning Coordinator Area are critical to the reliability of the BES to identify the facilities below 200 kV that must meet Requirement R1 to prevent cascading when protective relay settings limit transmission loadability. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

5.1 The Planning Coordinator shall have a process to use the criteria established within Attachment B to determine the facilities that are critical to the reliability of the Bulk Electric System.

5.2 Each Planning Coordinator shall maintain a current list of facilities determined according to the process described in Requirement R5 Part 5.1.

5.3 Each Planning Coordinator shall provide a list of facilities to its Regional Entity, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

FERC Order 733, ¶237: Modify sub-requirement R3.3 to add the RE to list of entities that receive the critical facilities list.

PRC-023 — 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).

FERC Order 733, ¶264: Revise section 1 of Attachment A to include supervising relay elements.

1.6. Protective functions that supervise operation of other protective functions in 1.1 through 1.5.

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.

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.

Standard Development Roadmap

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

Development Steps Completed:

1. The Standards Committee approved the SAR for posting on August 12, 2010.
2. SAR posted for formal comment on August 19, 2010.
3. Standard posted for informal comment period on August 19, 2010.

Proposed Action Plan and Description of Current Draft:

This is the first draft of the requirements developed to address the FERC directives in Order No. 733 and posted for an informal comment period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop second draft of SAR and respond to comments.	September, 2010 – October, 2010
2. Post the standard for 45-day comment period with concurrent ballot	October , 2010
3. Develop second draft of the standard and respond to comments.	December, 2010 – January, 2011
4. Re-ballot the proposed standard	January, 2011
5. NERC Board approval	February, 2011
6. Submit standard to FERC for approval	March, 2011

A. Introduction

1. **Title: Transmission Relay Loadability**

2. **Number:** PRC-023-~~1~~2

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~~Faults.

4. **Applicability:**

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

> FERC Order 733, ¶60: Apply an "add in" approach to sub-100 kV facilities.

4.1.1 Transmission lines operated at 200 kV and above.

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

> The SDT will ensure that 4.1.2 and 4.1.4 are consistent with the applicability methodology once it is developed.

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

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

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

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

> FERC Order 733, ¶284: Remove the exceptions footnote from the "Effective Dates" section.

4.4. Planning Coordinators.

5. **Effective Dates**~~[1]~~**:**

5.1. Requirement R1, Requirement R2, Requirement R3, Requirement R4:

5.1.1 For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) —the beginning of the first calendar quarter following applicable regulatory approvals.

5.1.2 For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals.

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

5.1.3 Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its Planning Coordinator pursuant to Requirement R5, Part ~~R~~5~~3~~.3 to comply with Requirement R1 (including all sub-requirements) for each facility that is added to the Planning Coordinator's critical facilities list determined pursuant to Requirement R5, Part ~~R3~~5.1.

5.2. Requirement R5~~3~~: 18 months following applicable regulatory approvals.

FERC Order 733, ¶244: Include section 2 of Appendix A as an additional Requirement.

B. Requirements

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

~~1.1~~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).

~~1.2~~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).

~~1.3~~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:

- ~~1.3.1~~ An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
- ~~1.3.2~~ An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance.

~~1.~~4. Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of:

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

~~1.4~~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).

[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.

~~1.5~~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.

~~1.6~~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.

~~1.7~~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.

~~1.8~~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 to the under any system configuration.

~~1.9~~10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer ~~so that they do not operate at or below the greater of~~such that the protection settings do not expose the limiting piece of equipment to fault level and duration that exceeds its capability and so that the relays do not operate at or below the greater of:~~:~~

> FERC Order 733, ¶203: Modify sub-requirement R1.10 to verify equipment is capable of sustaining the anticipated overload associated with the fault.

- 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.

~~1.10~~11. For transformer overload protection relays that do not comply with Requirement R1, Setting ~~1.~~10 set the relays according to one of the following:

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

~~1.11~~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:

~~1.12.1~~a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

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

~~1.12.2~~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.

~~1.12.3~~c. Include a relay setting component of 87% of the current calculated in Requirement R1, Setting 12~~1.12.2~~ in the Facility Rating determination for the circuit.

~~1.12~~13. Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.

R2. ~~The~~ Each Transmission Owner, Generator Owner, ~~or~~ and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, Settings~~1~~.6, ~~R1.~~7, ~~R1.~~8, ~~R1.~~9, ~~R1.~~12, or ~~R1.~~13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

> FERC Order 733, ¶186: Modify R1.2 to require that TOs, GOs, and DPs give their TOPs a list of transmission facilities that implement R1.2.

R3. ~~The~~Each Transmission Owner, Generator Owner, ~~or~~and Distribution Provider that sets transmission line relays according to Requirement R1 ~~part 1.2~~Setting 2 shall provide ~~their~~ its Planning Coordinator, Transmission Operator, Regional Entity, and Reliability Coordinator with a list of ~~transmission f~~facilities ~~that have~~associated with those transmission line relays ~~set so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating~~ at least once each calendar year, with no more than 15 months between reports ~~as described in R1.2.~~ [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]

> FERC Order 733, ¶203: Modify sub-requirement R1.10 to verify equipment is capable of anticipated overload.

~~The Transmission Owner, Generator Owner, or Distribution Provider that sets transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer based on the limitations described in R1.10 shall verify that the protection setting does not expose the limiting piece of equipment to fault level and duration that exceeds its capability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]~~

R4. Each Transmission Owner, Generator Owner, ~~or~~and Distribution Provider that sets transmission line relays according to Requirement R1 ~~part 1.~~Setting 12 shall provide a list of the facilities associated with those relays to ~~their~~its Regional Entity at least once each calendar year, with no more than 15 months between reports. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]

> FERC Order 733, ¶224: Make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant sub-requirement R1.12.of anticipated overload.

~~R3.~~R5. ~~The~~ Each Planning Coordinator shall apply the criteria in Attachment B to determine which of the facilities (transmission lines operated ~~at~~ below~~100 kV to~~ 200 kV and transformers with low voltage terminals connected ~~at 100 kV to~~below 200 kV) in its Planning Coordinator Area are critical to the reliability of the ~~Bulk Electric System~~BES to identify the facilities ~~from 100 kV to~~below 200 kV that must meet Requirement R1 to prevent ~~potential cascade tripping~~cascading ~~that may occur~~ when protective relay settings limit transmission loadability. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

> Attachment B is still under development.

5.1 The Planning Coordinator shall have a process to use the criteria established within Attachment B to determine the facilities that are critical to the reliability of the Bulk Electric System.

~~**1.3.1** This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.~~

5.2 ~~The~~ Each Planning Coordinator shall maintain a current list of facilities determined according to the process described in Requirement R5 ~~p~~Part 5~~3~~.1.

5.3 ~~The~~ Each Planning Coordinator shall provide a list of facilities to its Regional Entity, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to ~~the~~ that list.

FERC Order 733, ¶237: Modify sub-requirement R3.3 to add the RE to list of entities that receive the critical facilities list.

PRC-023 — 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. ~~Relay elements~~Protective functions that supervise operation of other protectiv~~e~~on functions in 1.1 through 1.5.

FERC Order 733, ¶264: Revise section 1 of Attachment A to include supervising relay elements.

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

~~3.~~2. The following protection systems are excluded from requirements of this standard:

~~3.1.~~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.

~~3.2.~~2.2. Protection systems intended for the detection of ground fault conditions.

~~3.3.~~2.3. Protection systems intended for protection during stable power swings.

~~3.4.~~2.4. Generator protection relays that are susceptible to load.

~~3.5.~~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.

~~3.6.~~2.6. Protection systems that are designed only to respond in time periods which allow 15 minutes or greater to respond to overload conditions.

~~3.7.~~2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

~~3.8.~~2.8. Relay elements associated with ~~DC~~ dc lines.

~~3.9.~~2.9. Relay elements associated with ~~DC~~ dc converter transformers.

Unofficial Comment Form for Relay Loadability Order (No. 733) (Project 2010-13)

Please **DO NOT** use this form. Please use the electronic form located at the link below to submit comments on the proposed standard, PRC-023-2 and on the associated SAR. The electronic comment form must be completed **by September 19, 2010**.

https://www.nerc.net/nercsurvey/Survey.aspx?s=c64a2b0a1f9d4e98aef8640932516830

If you have questions please contact Stephanie Monzon at Stephanie.monzon@nerc.net or by telephone at [610-608-8084

Project 2010-13: Relay Loadability Order (RLO SDT) – PRC-023-2

Background Information

NERC Standard PRC-023-1 – Transmission Relay Loadability was approved by FERC as mandatory and enforceable in March 2010, with direction that NERC make a number of changes.

The Standard Drafting Team has made changes to PRC-023 to address the following directives from Order 733

- p. 60 . . . modify PRC-023-1 to apply an “add in” approach to sub-100 kV facilities that are owned or operated by currently-Registered Entities or entities that become Registered Entities in the future, and are associated with a facility that is included on a critical facilities list defined by the Regional Entity.

- p. 186 . . . require that transmission owners, generator owners, and distribution providers give their transmission operators a list of transmission facilities that implement sub-requirement R1.2.

- p. 203 . . . modify sub-requirement R1.10 so that it requires entities to verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with the fault.• p. 224 . . . make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays

- p. 237 . . . modify the Reliability Standard to add the Regional Entity to the list of entities that receive the critical facilities list. [sub-requirement R3.3]

- p. 244 . . . include section 2 of Attachment A in the modified Reliability Standard as an additional Requirement with the appropriate violation risk factor and violation severity level.

- p. 264 . . . revise section 1 of Attachment A to include supervising relay elements on the list of relays and protection systems that are specifically subject to the Reliability Standard.

- p. 283 . . . modify the Reliability Standard to include an implementation plan for sub-100 kV facilities.

- p. 284 . . . remove the exceptions footnote from the “Effective Dates” section.

However, the directive below is not yet addressed, even though it is referenced within the draft standard text. It will be included in a subsequent posting of this draft standard.

- p. 69 . . . modify Requirement R3 of the Reliability Standard to specify the test that planning coordinators must use to determine whether a sub-200 kV facility is critical to the reliability of the Bulk-Power System.

To expedite the project to address the directives from FERC Order No. 733, the Standard Drafting Team is posting the draft modifications to PRC-023-1 for an informal comment period.

Please note that the posting of PRC-023-2 is an **INFORMAL** posting.

1. The Applicability Section (4.1.2 and 4.1.4) and Requirement R5 (previously Requirement R3) have been modified to address the directive in Paragraph 60 of Order no. 733. Do you agree that this is an acceptable and effective method of meeting this directive? If not, please explain.

☐ Yes

☐ No

Comments:

2. Requirement R1 has been modified to address the directive in Paragraph 244 of Order no. 733. Do you agree that this is an acceptable and effective method of meeting this directive? If not, please explain.

☐ Yes

☐ No

Comments:

3. Requirement R1, section 10 has been modified to address the directive in Paragraph 203 of Order no. 733. Do you agree that this is an acceptable and effective method of meeting this directive? If not, please explain.

☐ Yes

☐ No

Comments:

4. Requirement R3 has been added to address the directive in Paragraph 186 of Order no. 733. Do you agree that this is an acceptable and effective method of meeting this directive? If not, please explain.

☐ Yes

☐ No

Comments:

5. Requirement R4 has been added to address the directive in Paragraph 224 of Order no. 733. Do you agree that this is an acceptable and effective method of meeting this directive? If not, please explain.

☐ Yes

☐ No

Comments:

6. Requirement R5 and part 5.1 (previously Requirement R3 and part 3.1) have been modified to establish the framework to address the directive in Paragraph 69 of Order no. 733, although the criteria itself (which will be Attachment B) is still being

developed. Do you agree that this is an acceptable and effective method of meeting this directive considering that Requirement R5 is establishing the construct to insert the criteria at a future time in the form of Attachment B? If not, please explain.

☐ Yes

☐ No

Comments:

7. Attachment A has been modified to address the directive in Paragraph 264 of Order no. 733. Do you agree that this is an acceptable and effective method of meeting this directive? If not, please explain.

☐ Yes

☐ No

Comments:

8. Do you agree that the SDT has addressed the remaining directives: Paragraph 284 to remove the footnote and Paragraph 283 to modify the implementation plan for sub-100 kV facilities (by revising the Effective Date section of the standard)?

☐ Yes

☐ No

Comments:

Questions 9-13 relate to the SAR

9. Do you agree that the scope of the proposed standards action addresses the directive or directives?

☐ Yes

☐ No

Comments:

10. Can you identify an equally efficient and effective method of achieving the reliability intent of the directive or directives?

☐ Yes

☐ No

Comments:

11. Do you agree with the scope of the proposed standards action?

☐ Yes

☐ No

Comments:

12. Are you aware of any regional variances that we should consider with this SAR?

☐ Yes

☐ No

Comments:

13. Are you aware of any associated business practices that we should consider with this SAR?

☐ Yes

☐ No

Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standard Authorization Request Form

Title of Proposed Standard	Relay Loadability Order 733
Request Date	8/5/2010
SC Approval Date	8/12/2010

SAR Requester Information		**SAR Type** (*Check a box for each one that applies.*)	
Name	Stephanie Monzon	☒	New Standard
Primary Contact	Stephanie.monzon@nerc.net	☒	Revision to existing Standard
Telephone Fax	610-608-8084	☐	Withdrawal of existing Standard
E-mail	Stephanie.monzon@nerc.net	☐	Urgent Action

Purpose As the ERO, NERC must address all directives in Orders issued by FERC. On March 18, 2010 FERC issued Order No. 733 which approved Reliability Standard PRC-023-1 – Transmission Relay Loadability, and also directed NERC, as the Electric Reliability Organization (“ERO”), to develop certain modifications to the PRC-023-1 standard through its Reliability Standards development process, to be completed by specific deadlines. Attachment 1 to the SAR contains the directives and associated deadlines. The Order also directed development of two new Reliability Standards to address issues related to generator relay loadability and the operation of protective relays due to power swings. The standards-related directives in Order 733 are aimed at closing some reliability-related gaps in the scope of PRC-023-1.

Industry Need

FERC directed NERC to develop modifications related to Relay Loadability by specific deadlines in Order No. 733. Attachment 1 to the SAR contains the directives and associated deadlines.

<u>PRC-023-1 Directed Modifications</u>
The Commission directed a number of changes to the approved standard including a test to be applied by Planning Coordinators to determine applicability to elements operated at less than 200 kV. This test will be included in PRC-023-1 either in the form of a Requirement or as an attachment to the standard.

<u>Generator Step-up and Auxiliary Transformers</u>
The Commission directed the ERO to develop a new Reliability Standard addressing generator relay loadability, with its own individual timeline, and not a revision to an existing Standard.

<u>Protective Relays Operating Unnecessarily Due to Stable Power Swings</u>
The Commission observed that PRC-023-1 does not address stable power swings, and pointed out that currently available protection applications and relays, such as pilot wire differential, phase comparison and blinder-blocking applications and relays, and impedance relays with non-circular operating characteristics, are demonstrably less susceptible to operating unnecessarily because of stable power swings. Given the availability of alternatives, the Commission stated that the use of protective relay systems that cannot differentiate between faults and stable power swings constitutes miscoordination of the protection system and is inconsistent with entities’ obligations under existing Reliability Standards.

In this Final Rule the Commission decided not to direct the ERO to modify PRC-023-1 to address stable power swings. However, because both NERC and the U.S.-Canada Power System Outage Task Force have identified undesirable relay operation due to stable power swings as a reliability issue, the Commission directed the ERO to develop a Reliability Standard that requires use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases out protective relays that cannot meet this requirement.

Brief Description
This SAR’s scope includes three standard development phases to address the standards-related directives in Order No. 733 directives. Phase I is focused on making the specific modifications to PRC-023-1 that were identified in the order; Phase II is focused on

developing a new standard to address generator relay loadability; and Phase III is focused on developing requirements that address protective relay operations due to power swings.

Detailed Description

Phase I: Develop modifications to PRC-023-1- Transmission Relay Loadability by March 18, 2011 to address the following directives from Order 733:

- p. 60 . . . modify PRC-023-1 to apply an "add in" approach to sub-100 kV facilities that are owned or operated by currently-Registered Entities or entities that become Registered Entities in the future, and are associated with a facility that is included on a critical facilities list defined by the Regional Entity.
- p. 69 . . . modify Requirement R3 of the Reliability Standard to specify the test that planning coordinators must use to determine whether a sub-200 kV facility is critical to the reliability of the Bulk-Power System.
- p 162 . . . consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings.
- p. 186 . . . require that transmission owners, generator owners, and distribution providers give their transmission operators a list of transmission facilities that implement sub-requirement R1.2.
- p. 203 . . . modify sub-requirement R1.10 so that it requires entities to verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with the fault.
- p. 237 . . . modify the Reliability Standard to add the Regional Entity to the list of entities that receive the critical facilities list. [sub-requirement R3.3]
- p. 244 . . . include section 2 of Attachment A in the modified Reliability Standard as an additional Requirement with the appropriate violation risk factor and violation severity level.
- p. 264 . . . revise section 1 of Attachment A to include supervising relay elements on the list of relays and protection systems that are specifically subject to the Reliability Standard.
- p. 283 . . . modify the Reliability Standard to include an implementation plan for sub-100 kV facilities.
- p. 284 . . . remove the exceptions footnote from the "Effective Dates" section.

In Phase I of the project, the NERC Relay Loadability standard drafting team will either modify the PRC-023-1 Reliability Standard to incorporate the directed modifications or will propose equally efficient and effective alternative approaches that address the Commission's reliability-related concerns. *(In parallel with this effort, NERC plans to convene a panel of industry subject matter experts to develop a straw man proposal for the test Planning Coordinators must use to identify sub-200 kV facilities that are critical to the reliability of the Bulk Power System. The panel will collect industry feedback on the straw man test using the current standards development process that will be incorporated into Requirement R3 of PRC-023-1 by the Standard Drafting Team.)*

Phase II: Develop a new Standard Addressing Generator Relay Loadability
In Phase II of the project, a new Reliability Standard will be developed by the end of 2012 to address the subject of generator relay loadability in support of NERC's filing indicating it would develop such a standard and to address the following directive from Order No. 733:

- p. 108 . . . consider the PSEG Companies' suggestion in developing a Reliability

Standard that addresses generator relay loadability. As indicated in NERC's Order No. 733 clarification and rehearing request, NERC believes adding additional requirements to the PRC-023 standard in addition to developing a new Reliability Standard to address generator relay loadability could lead to confusion over applicability and the possibility of conflicting requirements. Therefore, NERC proposed in its clarification and rehearing request to address the issue of generator relay loadability in a new Reliability Standard, separate and distinct from the PRC-023 Reliability Standard, which is intended to address relays that protect transmission elements. Subject to the Commission's response to NERC's pending clarification and rehearing request, NERC plans to address generator relay loadability in a new Reliability Standard for applications where the relays are set with a shorter reach to protect the generator and the generator step-up transformer, and for applications where the relays are set with a longer reach to provide backup protection for transmission system faults. The standard drafting team will use relevant sections of the NERC technical reference document, Power Plant and Transmission System Protection Coordination Section 3.1 and Appendix E to develop the requirements by which generator relay loadability will be assessed. <u>Phase III: Development of a New Standard Addressing the Issue of Protective Relay Operations Due To Power Swings</u> In Phase III of the project, a new Reliability Standard will be developed to address the subject of protective relay operations due to power swings to address the following directive from Order No. 733 by the end of 2014: • p. 150 - develop a Reliability Standard that requires the use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Assurer	Monitors and evaluates the activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.
☒	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
PRC-023-1	Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability, and directed NERC, as the Electric Reliability Organization ("ERO"), to develop certain modifications to the PRC-023-1 standard through its Reliability Standards development process, to be completed by specific deadlines.
New Reliability Standard	Development of a New Standard Addressing Generator Relay Loadability
New Reliability Standard	Development of a New Standard Addressing the Issue of Protective Relay Operations Due To Power Swings

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Attachment 1 - Order No. 733 – Action Plan and Timetable

Note that the scope of the SAR is limited to addressing the directives highlighted in the table below.

Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability, and directed NERC, as the Electric Reliability Organization ("ERO"), to develop certain modifications to the PRC-023-1 standard through its Reliability Standards development process, to be completed by specific deadlines and directed NERC to develop requirements to address issues related to Relay Loadability. The Order also directed development of two new Reliability Standards to address issues related to generator relay loadability and the operation of protective relays due to power swings. The following table lists the FERC directives in Order No. 733 and for each directive associates it with a project phase. Note that some of the tasks within each phase will be managed by NERC staff, not the standard drafting team.

Paragraph	Text	Project Phase/ Timeline
60	With respect to sub-100 kV facilities, we adopt the NOPR proposal and direct the ERO to modify PRC-023-1 to apply an "add in" approach to sub-100 kV facilities that are owned or operated by currently-Registered Entities or entities that become Registered Entities in the future, and are associated with a facility that is included on a critical facilities list defined by the Regional Entity. We also direct that additions to the Regional Entities' critical facility list be tested for their applicability to PRC-023-1 and made subject to the Reliability Standard as appropriate.	Phase I -- by March 18, 2011
69	Finally, pursuant to section 215(d)(5) of the FPA, we direct the ERO to modify Requirement R3 of the Reliability Standard to specify the test that planning coordinators must use to determine whether a sub-200 kV facility is critical to the reliability of the Bulk-Power System. We direct the ERO to file its test, and the results of applying the test to a representative sample of utilities from each of the three Interconnections, for Commission approval no later than one year from the date of this Final Rule.	Phase I -- Note NERC's pending request for rehearing filed on April 19, 2010 regarding this directive.
97	Finally, commenters argue that there should be some mechanism for entities to challenge criticality determinations. We agree that such a mechanism is appropriate and direct the ERO to develop an appeals process (or point to a process in its existing procedures) and submit it to the Commission no later than one year after the date of this Final Rule.	Phase I – by March 18, 2011
105	In light of the ERO's statement that within two years it expects to submit to the Commission a proposed Reliability Standard addressing generator relay loadability, we direct the ERO to submit to the Commission an updated and specific timeline explaining when it expects to develop and submit this proposed Standard.	Phase II – by the end of 2012
108	Finally, the PSEG Companies suggest that the ERO consider whether a generic rating percentage can be established for generator step-up transformers and, if so, determine that percentage. Although we do not adopt the NOPR proposal, we encourage the ERO to consider the PSEG Companies' suggestion in developing a Reliability Standard that addresses generator relay loadability.	Phase II – by the end of 2012
150	However, because both NERC and the Task Force have identified undesirable relay operation due to stable power swings as a reliability issue, we direct the ERO to develop a Reliability Standard that requires the use of protective relay systems that can differentiate between faults and stable power swings and,	Phase III – by the end of 2014

Paragraph	Text	Project Phase/ Timeline
	when necessary, phases out protective relay systems that cannot meet this requirement. We also direct the ERO to file a report no later than 120 days of this Final Rule addressing the issue of protective relay operation due to power swings. The report should include an action plan and timeline that explains how and when the ERO intends to address this issue through its Reliability Standards development process.	
162	We agree with the PSEG Companies and direct the ERO to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings.	Phase I – by March 18, 2011
186	However, we will adopt the NOPR proposal to direct the ERO to modify PRC-023-1 to require that transmission owners, generator owners, and distribution providers give their transmission operators a list of transmission facilities that implement sub-requirement R1.2.	Phase I – by March 18, 2011
203	We adopt the NOPR proposal and direct the ERO to modify sub-requirement R1.10 so that it requires entities to verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with the fault.	Phase I – by March 18, 2011
224	While we are not adopting the NOPR proposal, we direct the ERO to document, subject to audit by the Commission, and to make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant sub-requirement R1.12.	Phase I – by March 18, 2011
237	We adopt the NOPR proposal and direct the ERO to modify the Reliability Standard to add the Regional Entity to the list of entities that receive the critical facilities list. [sub-requirement R3.3]	Phase I – by March 18, 2011
244	We adopt the NOPR proposal and direct the ERO to include section 2 of Attachment A in the modified Reliability Standard as an additional Requirement with the appropriate violation risk factor and violation severity level.	Phase I – by March 18, 2011
264	After further consideration, and in light of the comments, we will not direct the ERO to remove any exclusion from section 3, except for the exclusion of supervising relay elements in section 3.1. Consequently, we direct the ERO to revise section 1 of Attachment A to include supervising relay elements on the list of relays and protection systems that are specifically subject to the Reliability Standard.	Phase I – by March 18, 2011
283	Additionally, in light of our directive to the ERO to expand the Reliability Standard's scope to include sub-100 kV facilities that Regional Entities have already identified as necessary to the reliability of the Bulk-Power System through inclusion in the Compliance Registry, we direct the ERO to modify the Reliability Standard to include an implementation plan for sub-100 kV facilities.	Phase I – by March 18, 2011

Attachment 1 - Order No. 733 – Action Plan and Timetable

Paragraph	Text	Project Phase/ Timeline
284	We also direct the ERO to remove the exceptions footnote from the "Effective Dates" section.	Phase I – by March 18, 2011
297	Finally, we direct the ERO to assign a "high" violation risk factor to Requirement R3.	Filed with the Commission on April 19, 2010
308	Consequently, we direct the ERO to assign a single violation severity level of "severe" for violations of Requirement R1.	Filed with the Commission on April 19, 2010
310	Accordingly, we direct the ERO to change the violation severity level assigned to Requirement R2 from "lower" to "severe" to be consistent with Guideline 2a.	Filed with the Commission on April 19, 2010
311	Finally, we direct the ERO to assign a "severe" violation severity level to Requirement R3.	Filed with the Commission on April 19, 2010

Standards Announcement

Standards Authorization Request (SAR) and Draft Standard
Formal and Informal Comment Periods Open
August 19–September 19, 2010

Now available at:
http://www.nerc.com/filez/standards/Reliability_Standards_Under_Development.html

Project 2010-13: Revisions to Relay Loadability for Order 733

The drafting team associated with this project is seeking comments on a proposed SAR and an initial set of proposed requirements **until 8 p.m. Eastern on September 19, 2010.**

The SAR is being posted for a 30-day formal comment period and the standard is being posted for a 30-day informal comment period; comments on both the SAR and the proposed requirements will be collected using a single comment form.

Instructions

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page:
http://www.nerc.com/filez/standards/SAR_Project%202010-13_Order%20733%20Relay%20Modifiations.html

Next Steps

The drafting team will draft and post responses to comments received during this period.

- The SAR is being posted for a 30-day formal comment period. With a formal comment period the team is required to provide a response to each comment submitted.

- The proposed requirements in the standard are being posted for a 30-day informal comment period. With an informal comment period, for each question asked on the comment form, the drafting team will provide a summary response to indicate whether stakeholders support the proposed revision and to identify any additional changes made based on stakeholder comments. The team will not provide an individual response to each comment submitted.

Project Background

When FERC issued Order 733, approving PRC-023-1 — Transmission Relay Loadability, it directed several changes to that standard and also directed development of one or more new standards within specified time periods. NERC filed for clarification and rehearing asking for clarity and an extension of time to address the directives, however without a response to the requests for clarification and rehearing, NERC must progress as though these requests will be denied.

The SAR for Project 2010-13 subdivides the standard development related directives into three phases. Phase I addresses the specific directives from Order 733 that identified required modifications to various elements within PRC-023-1. Phase II addresses directives associated with development of a new standard to address generator relay loadabilty. Phase III addresses directives associated with writing requirements to address protective relay operations due to power swings.

Applicability of Proposed PRC-023-2

Distribution Providers that own specific facilities (see standard for details)
Generator Owners that own specific facilities (see standard for details)
Planning Coordinators
Transmission Owners that own specific facilities (see standard for details)

Standards Development Process

The Reliability Standards Development Procedure 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.

Individual or group. (36 Responses)
Name (20 Responses)
Organization (20 Responses)
Group Name (15 Responses)
Lead Contact (15 Responses)
Question 1 (32 Responses)
Question 1 Comments (36 Responses)
Question 2 (29 Responses)
Question 2 Comments (36 Responses)
Question 3 (29 Responses)
Question 3 Comments (36 Responses)
Question 4 (29 Responses)
Question 4 Comments (36 Responses)
Question 5 (27 Responses)
Question 5 Comments (36 Responses)
Question 6 (32 Responses)
Question 6 Comments (36 Responses)
Question 7 (32 Responses)
Question 7 Comments (36 Responses)
Question 8 (26 Responses)
Question 8 Comments (36 Responses)
Question 9 (27 Responses)
Question 9 Comments (36 Responses)
Question 10 (25 Responses)
Question 10 Comments (36 Responses)
Question 11 (27 Responses)
Question 11 Comments (36 Responses)
Question 12 (29 Responses)
Question 12 Comments (36 Responses)
Question 13 (29 Responses)
Question 13 Comments (36 Responses)

-
Individual
Gene Henneberg
NV Energy
Yes
No
The proposed phrase added to R1 is only a start: ". . . , and to prevent its out-of-step blocking schemes from blocking tripping for fault conditions." The specific wording proposed by the Drafting Team may prevent using the out-of-step-block functions of many modern and widely used line protection relays (e.g. SEL-321 and later models and GE-UR). These relay's OSB function first blocks the protection elements from tripping, then uses a short delay and/or other information to determine whether the observed and perhaps evolving condition really represents a fault, in which case the blocking is reset to allow tripping. Such a block/reset operation is the most common technology available and would appear to lie within the intent of FERC in paragraph 244, but could be excluded by the presently proposed language. If an out-of-step blocking phrase is inserted in Requirement R1 of the standard, the emphasis should be modified to read something like: ". . . , and its out-of-step blocking schemes must allow tripping for fault conditions." This standard should also require that out-of-step blocking settings coordinate with both the loadability and protection characteristics. The out-of-step blocking references would seem to fit best within the organization of the standard if included as a new Requirement R2 (FERC's paragraph 244 anticipates ". . . an additional Requirement . . ."), with re-numbering of the proposed R2 through R5 as R3 through R6. The essential content of the DT's proposed phrase in R1 would be included as part of this new R2, which would read something like: R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate its out-of-step blocking schemes to ensure that both: R2.1. Out-of-step blocking schemes allow tripping for fault conditions during the loading conditions determined from Requirement R1 parts R1.1 through R1.13. R2.2. Relay out-of-step blocking settings coordinate with both the relay loadability characteristic determined from Requirement R1 parts R1.1 through R1.13 and the facility protection settings. The Measure for this proposed R2 would read something like: M2.The Transmission Owner, Generator Owner, and Distribution Provider with out-of-step blocking schemes shall have evidence such as spreadsheets or summaries of calculations to show that each of its out-of-step blocking schemes is set to comply with the requirements of R2.1 and R2.2. The VSL for R1 would not change; specifically it would not reference out-of-step blocking schemes. The VSL for this proposed new R2 would be "Severe" and read something like: A Transmission Owner, Generator Owner, or Distribution Provider did not allow its out-of-step blocking schemes to trip for fault conditions during the loading conditions determined from Requirement R1 parts R1.1 through R1.13. OR A Transmission Owner, Generator Owner, or Distribution Provider did not coordinate operation of its out-of-step blocking schemes with both the relay

loadability characteristic determined from Requirement R1 parts R1.1 through R1.13 and the facility protection settings.
Yes
Yes
Yes
No
This approach is not yet an acceptable and effective method of meeting the directive of paragraph 69. Whether it becomes an acceptable and effective method of meeting the directive will depend on the content of Attachment B. I'll reserve specific judgment and concerns until Attachment B is available for comment.
Yes
Yes
Yes
No
NERC's proposed Phase I, II, II process seems reasonable.
Yes
No
Individual
Steve Wadas
NPPD
Yes
As long as you keep BES.
Yes
I'm ok with that. It could have easily been left in Attachment A. You didn't bring the other language from attachment A to R1. You could of created a separate requirement for OOS, but I'm fine with moving it to R1.
No
Setting the relay to 150% of a 336MVA or 500MVA transformer can force you to cross the transformer damage curve and now your transformer is at risk to loss of life.
Yes
Yes
No
Attachment B has not even been developed.
No
Please remove Attachment A, R1.6. "Protective functions that supervise operation of other protection functions in 1.1 through 1.5.". If you do not remove R1.6 you must provide a detailed explanation of what supervise operation means and give examples. Utilities have thousands of relays that have imbedded fault detective supervision overcurrents for phase distance elements that are set at 0.5 amps or some similar value. This can not be changed. From your requirement these utilities would have to replace all of these relays or we would have to lower the Facality rating to 0.5 amp secondary/150%. You are also stating that if we have an external phase overcurrent fault detector that supervises a phase distance relay that this fault detector must now have to meet Requirement 1. This is an unacceptable requirement if this is your intent. You are putting the system at risk if this is your intent. We must set our relays to protect the line. We must also set fault detectors to pickup for all faults considering N-1 conditions at a minimum where the strongest source must be remove and the relays must still clear the fault. Please do not lose focus of the purpose: "Protective relay settings shall be set to reliably detect all fault conditions and protect the electrical network from these faults". If you have questions on my comments feel free to contact me. Steve Wadas, NPPD, 402 563 5917 Wk.
Yes
No
No
No

No
Yes
See Question 7.
Group
E.ON U.S. LLC
Brent Ingebrigtson
No
E.ON U.S. believes that it is confusing the way R5 is currently written due to the last part of the sentence " … when protective relay settings limit transmission loadability." There is a need for clarification on how this is to be applied. As an alternative: If the directive is to have the Planning Coordinator determine which sub-100kV facilities should be subject to the Reliability Standard; R5 should be modified to read "Each Planning Coordinator shall apply the criteria in Attachment B to determine which of the facilities in its Planning Coordinator Area are to be included in 4.1.2 and 4.1.4."
No
Since correct operation of the out-of-step blocking feature is integral to and only a single component of a successful trip operation (for fault conditions), this is already included in the requirement to "maintain reliable protection of the BES for all fault conditions" and does not have to be mentioned separately. Also, R1 (as written) may be interpreted to require one of the settings (1 through 13) to be used to prevent out-of-step blocking schemes from blocking tripping for fault conditions. But Settings 1 thru 13 do not address specific setting criteria for out-of-step blocking.
No
E.ON U.S. is concerned that the proposal requires a fault protection scheme separate from the phase overload relays. With the phase overload relays set at 150% of the maximum transformer nameplate, they (by themselves) will not be able to coordinate with the transformer damage curve (as defined by IEEE) for low level faults. R1, Section 10 meets the directive of Paragraph 203; however it is not clear that Section 10 only applies when there is no high side breaker at the transformer, as discussed in Order No. 733. E.ON U.S. recommends that an exclusion of the transmission line relay settings should be considered when transformer overload protection is provided by other means (i.e. A low side breaker trip or a direct transfer trip of the remote breaker initiated by an overload relay installed on the transformer).
Yes
Yes
No
See comments for item #1.
No
E.ON U.S. requests a clarification of "protective functions" such that it applies only to those protective relay elements that would respond to non-fault or load conditions, and could issue a direct trip, upon operation, during a loss of communication or loss of potential condition.
No
Cannot assess the impact until Attachment B is developed and commented sections above are clarified.
No
See commented sections above. Also, the directive identified in Paragraph 224 was not included in the detailed description or highlighted in Attachment 1 of the SAR. However it was included in the proposed modifications as R4.
Yes
No
No
No
Individual
Joylyn Faust
Consumers Energy
Yes
Yes
Yes
Yes
Yes

Yes
We are concerned about the criteria still undergoing development, and will offer any relevant comments on that criteria when it is published.
No
The supervising elements addressed within this change may fundamentally be unable to be set in accordance with the requirements of PRC-023, while still permitting the Protection System to function properly for fault conditions. The supervising element is usually present to assure that a distance element does not operate inadvertently for close-in zero-voltage faults near the relay location in the non-trip direction, but does not, by itself, produce a trip. We appreciate that NERC must respond to this directive, but believe that the change, as expressed, will be detrimental to reliability.
Yes
Yes
Yes
NERC should, again, oppose the FERC directive in paragraph 264, since, as explained above, this directive is both unnecessary and detrimental to reliability.
Yes
No
No
Individual
Jonathan Meyer
Idaho Power - System Protection
Yes
Yes
No
The reworded Requirement should to be clarified. The fault level and duration that the limiting element will be exposed can be a function of fault location and contingencies, such as relay failures, that are not addressed or defined. No measure is specified in the reliability standard that will demonstrate compliance with the revised requirements in R1.10.
Yes
Yes
No
It is not acceptable or effective until Attachment B is completed and available for review.
Yes
The order has been met, but there is significant concern about the inclusion of supervisory elements in protective systems. A supervisory element is not performing a tripping function. As stated in Attachment A “This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:…”. Supervisory elements, used properly, do not trip for load current.
Yes
Yes
No
Yes
No
No
Group
Northeast Power Coordinating Council
Guy Zito
No

The revised Applicability paragraph 4.1.4 reads: 4.1.4 Transformers with low voltage terminals connected below 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System (BES). The phrase "low voltage terminals" is open to interpretation because some transformers have low-voltage terminals which are do not supply a load, or supply only local substation AC service. Sometimes the transformer is a 3-winding bank, with the low-voltage winding not used, or the low-voltage winding is used solely to provide additional grounding, as in the case of a delta-connected tertiary, unconnected to any load. Is this what is intended? If yes, then they should remove the ambiguity. Note the phrase "low-voltage" terminal was part of Revision 1 and is unchanged by Revision 2, however, the new applicability to below 200 kV raises the new concern. What is meant by “critical to the reliability of the Bulk Electric System (BES)”? Also, replace “as designated” with “and designated”. Suggest 4.1.4 be revised to read: 4.1.4 Transformers with low voltage terminals connected below 200 kV and designated by the Planning Coordinator as Critical Assets. Clarification is needed to explain the disconnect between FERC’s “sub-100kV”, and the proposed “below 200kV”.
No
The last sentence in R1 should be revised to read: 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. Settings are to be applied as listed following: “Setting” should be replaced throughout R1 when referring to a part, or sub-requirement of R1. The terminology should be whatever is preferred by NERC. Requirement R1, Parts 7, 8 and 9: Requirement R1, Parts 7, 8 and 9, replace the phrase “under any system configuration” with "under any system condition:" 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 condition. 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 condition. 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 [___] to the under any system condition. [Brackets added, also see further comment on missing wording following] This phrase "under any system configuration" could be construed as being too all-inclusive, as one could postulate multiple events, e.g., simultaneous outages, which however unlikely could permit power flows in a direction for which the system was not originally designed. As with the second comment below, the phrase "under any system condition" was part of Revision 1 and is unchanged by Revision 2, however, the new applicability to below 200 kV creates the new concern. Requirement 1, part 9: As currently written, Requirement 1, part 9 states: 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 [___] to the under any system configuration. [Brackets added] Some words are missing. The brackets have been added above to show one place where at least some of the needed wording may be missing. A rewrite is necessary in order for this sentence to make any sense.
Yes
No
Referring to the response to Question 2 above, “Setting” should be replaced with Part, or Sub-requirement, whichever is the terminology preferred by NERC to use.
No
R4 addresses the directive, but as commented on previously, “Setting” should be replaced with Part, or Sub-requirement, whichever is the terminology preferred by NERC to use.
No
Requirement R5 states that the Planning Coordinator will determine which facilities below 200kV are critical to the reliability of the Bulk Electric System by applying criteria defined in Attachment B, which is to be developed. Therefore, respondents cannot comment on Attachment B. Respondents reserve the right to comment when Attachment B is available for review. Because the document has been presented to the industry without Attachment B, how will Attachment B be presented to the industry? Regarding sub-requirement 5.3, it must be revised to clarify that the Planning Coordinator will provide the list of facilities subject to the Standard to all of the TOs, GOs, and DPs registered in its footprint, not just to those entities that have facilities on the list. 5.2 refers to “Part 1”. As commented on previously in Question 5 and elsewhere, Part or Sub-requirement should be used for consistency.
Yes
Yes
Yes
No
Yes
No
No
Individual
Michael Gammon
Kansas City Power & Light

No
Agree the changes for 4.1.2 and 4.1.4 are effective in meeting the “add in” approach in the FERC order. However, do not agree with the approach in R5. R5 proposes to establish the criteria by which Reliability Coordinators will determine facilities critical to the reliability of the BES. There are a variety of differing, and often complex, operating conditions that dictate the need for transmission facilities. The TPL standards require extensive studies of the transmission system be performed under steady state and dynamic conditions to understand and identify sensitive areas of the transmission system and enable Reliability Coordinators to identify flowgates in their respective regions. In light of the Reliability Coordinators awareness of transmission sensitivities through these studies, it seems unnecessary to dictate to the Reliability Coordinators additional criteria.
Yes
No
Although setting #10 includes language to protect the most limiting element for a transmission circuit ending with a transformer, the relay settings in the bulleted items are absent any consideration for other elements such as disconnect switches, wave traps, current transformers, potential transformers, etc. and are only with concern to the transformer. The relay settings should consider the fault current capabilities of all the facilities involved and be set in magnitude and duration of the lowest facility rating.
No
Do not agree that the Regional Entity be included as a recipient of the list of transmission facilities. By NERC definition, the Regional Entity is the Compliance Monitor and Enforcement Authority for the NERC Reliability Standards and is not an operating entity. It is inappropriate to include Regional Entities as an entity to provide this information outside of the audit process established by the NERC Rules of Procedure. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to obtain this information. See definition below: Regional Entity – The term ‘regional entity’ is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE’s. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.
No
The proposed R4 exceeds the concerns of FERC in this matter. FERC directed a requirement to provide information upon request. The proposed R4 requires data submission without request of the parties with interest to the information. Recommend the SDT consider modifying this requirement to provide this information upon the request of appropriate operating parties. Do not agree that the Regional Entity be included as a recipient of the list of transmission facilities. By NERC definition, the Regional Entity is the Compliance Monitor and Enforcement Authority for the NERC Reliability Standards and is not an operating entity. It is inappropriate to include Regional Entities as an entity to provide this information outside of the audit process established by the NERC Rules of Procedure. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to obtain this information. See definition below: Regional Entity – The term ‘regional entity’ is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE’s. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.
No
Do not agree with the approach in R5 and R5.1. This proposes to establish the criteria by which Reliability Coordinators will determine facilities critical to the reliability of the BES. There are a variety of differing, and often complex, operating conditions that dictate the need for transmission facilities. The TPL standards require extensive studies of the transmission system be performed under steady state and dynamic conditions to understand and identify sensitive areas of the transmission system and enable Reliability Coordinators to identify flowgates in their respective regions. In light of the Reliability Coordinators awareness of transmission sensitivities through these studies, it seems unnecessary to dictate to the Reliability Coordinators additional criteria. In addition, in R5.3, do not agree that the Regional Entity be included as a recipient of the list of transmission facilities. By NERC definition, the Regional Entity is the Compliance Monitor and Enforcement Authority for the NERC Reliability Standards and is not an operating entity. It is inappropriate to include Regional Entities as an entity to provide this information outside of the audit process established by the NERC Rules of Procedure. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to obtain this information. See definition below: Regional Entity – The term ‘regional entity’ is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE’s. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.
Yes
No
It is inappropriate for this standard to supersede any other agreements and the provisions of those agreements that have been established between NERC and Registered Entities. The footnote made it clear those agreements would continue to

be honored. Recommend the SDT reinstate the principles established by the footnote directly into the Effective Dates section to recognize the authority of those agreements. Agree with the effective dates of 18 months after applicable approvals for R5 and for 24 months after notification by the Planning Coordinator of a new critical facility.
Yes
Agree that the SDT has made revisions that attempted to address the FERC directives. Do not agree with all the proposals by the SDT as indicated by the comments regarding questions 1 through 8.
No
No other comments.
No
Do not agree with all the proposals by the SDT as indicated by the comments regarding questions 1 through 8.
No
No
Group
Transmission Access Policy Study Group
William Gallagher
No
The modifications to the Applicability Section meet the FERC directive but have the unacceptable unintended consequence of increasing the burden on DPs with no reliability benefit. Specifically, the modifications make all DPs potentially subject to PRC-023, thus requiring all DPs to incur costs to determine whether the standard is applicable to them. Because PRC-023 should never be applicable to a DP in its capacity as a DP (as opposed to a TO that also happens to be registered as a DP), as explained in TAPS' response to question 6 below, the SDT should simply remove DPs from the Applicability section to prevent the significant potential for confusion and unnecessary costs.
No
The proposed method of identifying facilities to which the standard will apply may be reasonable, though we cannot comment definitively until a draft of Attachment B is available. The standard should not be applicable to DPs, however. TAPS has been unable to find or think of an example in which a DP would have a load-responsive transmission phase protection system, aside from a DP that is also a TO and has such a phase protection system because of its TO function. There is thus no reason to include DPs as potentially applicable entities. If the SDT retains DPs on the list of potentially applicable entities, it should at minimum clarify Requirement R5.3 to state that the Planning Coordinator will provide the list of facilities subject to the standard to all of the TOs, GOs and DPs registered in its footprint, not just to the entities who have facilities on the list. It is important that DPs who do not have facilities on the list have documentation from the Planning Coordinator demonstrating that fact.
Individual
Dan Rochester
Independent Electricity System Operator
Yes
We agree with the Applicability Section and the modification to R5. Note that there is a discrepancy between the entities listed in the Applicability Section and those checked off in the SAR. The latter indicates that the SAR is also applicable to the RC, which we do not believe is required.
No
We agree with the inclusion of Section 2 of Attachment A in the Requirement Section but the proposed modification may not fully meet the directive that the additional requirement is assigned a VRF and VSL. This may require the creation of a separate main requirement rather than simply including the condition as a part of a requirement.
No
The proposed revision goes beyond what's asked for in the directive as it requires the responsible entities to provide the list to entities other than the TOP. The directive asks for providing the list to the TOP only.
No
The objective of R4 as written is unclear. We speculate that by requiring the TOs, GOs and DPs to provide the list (associated with R1. Section 12) to the REs. the ERO will collect the relevant information from all REs to facilitate

provision of such information to owners, users and operators of the BES upon request. If this is the intent, we suggest to replace "REs" with "ERO" to make it a more direct and efficient way to provide the information needed to support the request for information process. The requirement as written does not conform with the results-based concept in that it does not clearly specify a reliability directive. Hence alternatively, we suggest removal of this requirement altogether since the directive asks the ERO to document, subject to audit by the Commission, and to make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities. This can be dealt with outside of the standard process, for example, through RoP 1600.
No
We are unable to assess its acceptability and effectiveness until Attachment B is developed.
Yes
No
We are unable to comment on this in the absence of a proposed implementation plan.
Yes
As indicated in our comment submitted under Q1, there is a discrepancy between the entities listed in the Applicability Section and those checked off in the SAR. The latter indicates that the SAR is also applicable to the RC, which we do not believe is required.
Yes
We general agree with the proposed action but there are detailed changes that we have comments on, which are noted in our comments under Q1 to Q8
No
No
Individual
Bill Miller
ComEd
Yes
Yes
Yes
Yes
Yes
Yes
No
1) Certain relay elements may be thought to be "supervising relay elements", when their function is specific and more limited. A very common example would be a phase overcurrent relay that is required to actuate along with a phase distance relay to cause a trip. In many applications, the phase overcurrent relays function is only to assure that the phase distance relay will not cause a trip when a line is taken out of service and no potential restraint is applied to the phase distance relay. Thus, loadability of the phase overcurrent relay is not a concern. Raising the level of the overcurrent element may negatively impact the fault detecting ability of the two relays. This is perhaps a limited function supervising relay element. It is complementary to the phase distance relay which provides the necessary loadability. 2) Although we don't employ out of step tripping, it would seem that the argument for the overcurrent element of an out of step tripping scheme would be the same as for the phase distance element. 3) Are there supervisory elements for switch onto fault schemes that could limit loadability? 4) In our experience, relays that supervise overcurrent relays are typically specifically designed to provide loadability in order to allow the overcurrent relay to provide greater sensitivity without worrying about its loadability. Thus this requirement would limit the use of such a scheme. 5) FERC's main example seems to refer to an old style of current differential relaying scheme that is likely not very widely applied. Most modern current differential schemes use digital communications and will not trip on loss of communications regardless of the settings of any elements that may be considered to be supervisory relay elements. The drafting team should consider modifying 1.6 of Attachment A to clarify and more specifically address the FERC concern. Three suggestions are as follows: 1) 1.6. Protective functions that supervise operation of other protective functions in 1.5. This is required for communications aided protection schemes in 1.5 only when those schemes require communication channel integrity to maintain scheme loadability. 2) 1.6. Protective functions that supervise operation of other protective functions in 1.2 through 1.5. This is required for communications aided protection schemes in 1.5 only when those schemes require communication channel integrity to maintain scheme loadability. 3) 1.6. Protective functions that supervise operation of other protective functions in 1.2 through 1.5.
Yes

Yes
No
No, other than the comments provided for question 7.
Yes
Yes, given that we assume that NERC must address all the FERC directives whether or not NERC or the industry agrees with them.
No
No
Individual
Kasia Mihalchuk
Manitoba Hydro
Yes
Yes
Yes
Yes
Yes
Yes
No
Item 1.6 in Attachment A is not necessary. If the protection functions in 1.1 through 1.5 already meet all the loadability requirements, the facility would not trip under heavy load condition by the supervising protection element alone. The directive in paragraph 264 of Order 733 seems to deal with the supervising protection element on the current differential scheme only. It is still arguable whether it is better to allow tripping of the line or restrain from tripping during loss communication and heavy loading condition.
No
Even though this version of the standard does seem to have addressed Paragraph 284 of Order 733, we still do not agree with the uniform effective date without taking into consideration how many critical circuits or equipment could be added for an individual utility.
Yes
Yes
The effective date can be dependent upon how many critical circuits or equipment are identified for each individual company.
Yes
No
No
Group
Arizona Public Service Company
Jana Van Ness, Director Regulatory Compliance
No
Agree with the content. However, there is no justification for VRF to be High for the circuits lower than 200 kV.
Yes
Yes
Yes
No
FERC Order required the list to be made available for review to users, owners and operators of the Bulk-Power System

upon request. Requirement 4 does not include the "request" requirement, implying that the Registered Entity must provide the list without a request. Further, the requirement does not specify what the Regional Entity will do with the list once it is provided.
Yes
Yes
Yes
Yes
No
No
Individual
Brian Evans-Mongeon
Utility Services
No
The modifications to the Applicability Section meet the FERC directive but have the unacceptable unintended consequence of increasing the burden on DPs with no reliability benefit. Specifically, the modifications make all DPs potentially subject to PRC-023, thus requiring all DPs to incur costs to determine whether the standard is applicable to them. Because PRC-023 should never be applicable to a DP in its capacity as a DP (as opposed to a TO that also happens to be registered as a DP), as explained in our response to question 6 below, the SDT should simply remove DPs from the Applicability section to prevent the significant potential for confusion and unnecessary costs.
No
The proposed method of identifying facilities to which the standard will apply may be reasonable, though we cannot comment definitively until a draft of Attachment B is available. The standard should not be applicable to DPs, however. We have been unable to find or think of an example in which a DP would have a load-responsive transmission phase protection system , aside from a DP that is also a TO and has such a phase protection system because of its TO function. There is thus no reason to include DPs as potentially applicable entities. If the SDT retains DPs on the list of potentially applicable entities, it should at minimum clarify Requirement R5.3 to state that the Planning Coordinator will provide the list of facilities subject to the standard to all of the TOs, GOs and DPs registered in its footprint, not just to the entities who have facilities on the list. It is important that DPs who do not have facilities on the list have documentation from the Planning Coordinator demonstrating that fact.
Group
Pepco Holdings, Inc - Affiliates
Richard Kafka
Yes
While philosophically we do not agree that this standard should apply to facilities below 100kV (i.e. facilities that are not defined as BES facilities) we believe that as long as a sound engineering methodology is developed and applied uniformly to identify those facilities critical to the reliability of the BES, then the revised wording is acceptable. Our response, however, is qualified based on being granted an opportunity to comment and vote on the methodology once it is developed.
No
The revised wording in paragraph R1 regarding out-of-step blocking schemes is confusing. We suggest rewording the paragraph by splitting the sentence as follows: …while maintaining reliable protection of the BES for all fault conditions. Use of out-of-step blocking schemes shall be evaluated to ensure that they do not block tripping for faults during the loading conditions defined within these requirements.
No

It would appear that this requirement has already been addressed in the R1 introductory paragraph by the phrase "...while maintaining reliable protection of the BES for all fault conditions." How could one "maintain reliable protection of the BES" if relays are set with operating times that result in equipment being exposed to fault levels and durations that exceed their capability. This introductory requirement to provide reliable fault protection applies to all sub requirements not just to section 10 (old R1.10). As such, the added language in section 10 seems redundant and superfluous. Secondly, if the proposed language were to remain in section 10, why is the term "limiting piece of equipment" used and not just "transformer"? It appears the major concerns related to the comments contained in Order 733 were around exceeding transformer fault level/duration limitations. If that is the concern, why not just use the phrase "do not expose the transformer to fault levels and durations that exceeds its capability"
No
To avoid confusion, the wording of R3 should be revised as follows: "Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to utilize Requirement R1 Setting 2 as the basis for verifying transmission line relay loadability shall provide…." The problem with the SDT's proposed wording of R3 is that suppose a TO chose to utilize R1 Setting 1 criteria (> 150% of 4 hr rating) as their basis for verifying loadability, but the actual relay setting also satisfied criteria R1 Setting 2 (> 115% of 15 min rating) the entity may interpret that they are still obligated to forward the list since the relay settings also satisfied R1 Setting 2 criteria
Yes
Yes
While philosophically we do not agree that this standard should apply to facilities below 100kV (i.e. facilities that are not defined as BES facilities) we believe that as long as a sound engineering methodology is developed and applied uniformly to identify those facilities critical to the reliability of the BES, then the revised wording is acceptable. Our response, however, is qualified based on being granted an opportunity to comment and vote on the methodology contained in Attachment B once it is developed.
No
We do not agree with the proposed wording of Section 1.6 of Attachment A which makes the standard apply to "Protective functions that supervise operation of other protective functions in 1.1 through 1.5". The standard should apply to "protective systems" not individual components of protective systems. Compliance should be based on the ability of the "protective system" as a whole to meet the performance criteria established by the standard. Delving into the details of individual scheme designs and supervising element operation goes well beyond the purpose and scope of this standard. In paragraph 251 of Order 733 the Commission "expressed concern that section 3.1 could be interpreted to exclude certain protection systems that use communications to compare current quantities and directions at both ends of a transmission line, such as pilot wire protection or current differential protection systems supervised by fault detector relays" and requested comment on "whether it should direct the ERO to modify section 3.1 to clarify that it does not exclude from the requirements of PRC-023-1 pilot wire protection or current differential protection systems supervised by fault detector relays." The Commission reiterated again in paragraphs 266, 268, and 270 their concern with not including supervising elements associated with "current differential schemes" to prevent them for operating on loss of communications. That being said, the proposed revision to Attachment A to include supervising elements for all protective functions in 1.1 through 1.5 goes well beyond addressing the Commission's concern. We believe the Commission's concern could be addressed by simply modifying Attachment A by deleting proposed section 1.6 and adding a new section 1.5.5 "Line current differential schemes, including supervising overcurrent elements". The SDT's current proposed wording for Section 1.6 would require the overcurrent element in a switch-on-to-fault scheme to be subject to the loadability criteria. However, the NERC SPCTF in their June 7, 2006 technical paper "Switch-on-to-Fault Schemes in the Context of Line Relay Loadability" indicated there is no suggested loadability criterion if the voltage arming threshold is set low enough. Similarly, fault detectors which supervise distance elements would be subject to the loadability standard. However, there are no criteria established on how to set these elements, particularly on weak source systems, or zone 3 applications, where in order to reliably detect faults at the end of the zone of protection may require setting the supervising fault detector below 150% of line rating. The NERC SPCTF in their June 7, 2006 technical paper "Methods to Increase Line Relay Loadability" provided recommendations to increase loadability of distance elements through various techniques, such as the use of load encroachment elements or blinders, but does not specifically address setting of supervising elements. In fact, at present, there is no reliability standard requiring the use of supervising elements, and some newer microprocessor relays do not even employ supervising fault detectors on their distance elements. FERC in their Order 733 stated "As with our other directives in this Final Rule, we do not prescribe this specific change as an exclusive solution to our reliability concerns regarding the exclusion of supervising relay elements. As we have stated, the ERO can propose an alternative solution that it believes is an equally effective and efficient approach to addressing the Commission's reliability concerns." In summary, we believe that addressing the Commission's concern regarding supervising elements on current differential schemes, as described in our second paragraph above, would satisfy the intent of Order 733, while not imposing unnecessary additional restrictions on what has proven historically to be extremely reliable protection practices.
No
We agree with the removal of the footnote regarding temporary exceptions. However, there appears to be a contradiction between the effective dates for sub 200kV facilities noted in section 5.1.2 (39 months following regulatory approvals) and 5.1.3 (24 months after being notified by its Planning coordinator). If the planning coordinator takes the full 18 months to determine the R5 list (per effective date section 5.2) and the TO has 24 months after that to comply, that would be 42 months following regulatory approval, which is in conflict with the 39 month requirement in 5.1.2. Since the list of sub 200kV facilities may change from year to year, it would seem prudent to make the effective date for those facilities always tied to a defined interval following being notified by the Planning Coordinator and eliminate the 39 month requirement for sub 200kV facilities from 5.1.2. Also, since the Attachment B methodology has not yet been determined, it is unclear how many sub 200kV facilities may fall under these requirements. As such, one cannot yet determine if the proposed 24 months would be sufficient. We propose at least a 36 month interval until the methodology is finalized and the magnitude of the scope better defined. In addition, if supervising elements are included in the standard in some form, an

implementation schedule (i.e. appropriate effective dates) need to be developed based on this significant increase in scope and number of facilities to be reviewed.
Yes
While the scope of the proposed standards action addresses the directive(s) outlined in FERC Order 733 we believe that there are two significant issues that need to be much more thoroughly investigated before being included. Those areas are the inclusion of supervising elements in the existing relay loadability standard and the development of any new standard that would “require the use of protective relay systems that can differentiate between faults and stable power swings and when necessary phase out protective relay systems that cannot meet this requirement.”
Yes
Regarding the response of protective relay systems to stable power swings, Draft 5 of TPL-001-2 Requirement R4 (stability assessment) section 4.3.1 requires a contingency analysis be performed which includes “tripping of transmission lines and transformers where transient swings cause protection system operation based on generic or actual relay models.” Therefore the impact of power swings on relay operation is already addressed in TPL-001. If the tripping of a line is identified during this study phase the impact of the line trip is assessed to ensure the system meets the performance criteria identified in Table 1. If not, mitigating measures would be required, such as modifying that protection scheme to prevent its operation during a stable power swing. However, this would be done on a case by case basis when identified. This seems a much more prudent approach than to require “all protection systems be modified to prevent operation during stable power swings.” That would be similar to requiring the re-conductoring all lines so that they could never experience an overload. Also, Appendix F of the “PJM Relay Subcommittee Protective Relaying Philosophy and Design Standards” employs a methodology to address relay response during power swings by calculating a transient load limit for the relay instead of just the steady state limit identified in PRC-023. The relay loadability is evaluated at the maximum projection along the +R axis (the most susceptible point for swings to enter) rather than at a 30 degree load angle. Various multiplying factors are used to account for the relay operating time delay. This methodology of calculating relay transient loadability limits, which was developed by the PJM Relay Subcommittee over 30 years ago, has worked extremely well in eliminating relay operations during stable power swings. In summary, there are other methods to evaluate and improve the performance of protection systems during power swings short of hardware replacements. All options should be evaluated.
No
We do not agree with the scope of the proposed standards action for numerous reasons. The documented responses to the original FERC NOPR on PRC-023 from numerous sources, including NERC and EEI, together make a rather convincing technical argument against many of these proposed actions. We support these technical arguments, which for the sake of brevity will not be repeated here. In addition, we have provided comments and objections on specific portions of the proposed standards action in our responses to questions 1 through 10 above.
No
No
Group
American Transmission Company
Andrew Z. Pusztai
Yes
However, this affirmative response is conditional depending on whether the criteria that will be established within Attachment B (see R5.1) are reasonable and apply to properly qualified facilities below 200 kV.
Yes
Yes
The word change meets the strict interpretation of the directive, but it is not necessarily improving the reliability of the system. Faults are cleared in cycles and transformer damage curves do not start until at least one second.
Yes
Yes
While achievable, this will not come without effort and does not necessarily improve the reliability of the BES commensurate with the compliance burden.
No
As noted in Q1 above, an affirmative response would be conditional and depend on whether the criteria that will be established within Attachment B (see R5.1) are reasonable and apply to properly qualified facilities below 200 kV. In addition, the R5 requirement should include wording that limits the scope of the transmission facilities (line and transformer circuits) to be evaluated to only those transmission facilities that can be tripped by the relay settings subject to requirement R1. Requirement R5 should also qualify that only the transmission facilities that are “known” to be associated with the relay settings subject to requirement R1 need to be evaluated. If the SDT wants to better assure that the Planning Coordinator knows about all of the pertinent transmission facilities, then they should add a requirement that obligates Transmission Owners, Generator Owners, and Distribution Providers to provide the Planning Coordinator with a list of the transmission facilities that are associated with the relay setting subject to requirement R1.
No
In Order 733, the Commission cites in footnote 186 (p. 161) the definitions of dependability and security, two components of reliability for protective relays. The Commission did not recognize that the two tend to be mutually exclusive. Raising dependability (making sure breakers trip during a fault) can sacrifice some degree of security (tripping more than is needed). Historically, protection engineers have been biased toward dependability to ensure the safety of people and

equipment. The exclusions allow that to happen. These are contingency scenarios where protective schemes are compromised. For a second contingency, the dependability is at risk if fast tripping is not employed. By removing the exclusion, reliability could be negatively jeopardized. For example, an operational decision to open breakers will be needed for loss of potential. The corollary would be leaving the element in service with fast tripping enabled for a fault until the loss of potential condition can be diagnosed and corrected
Yes
Yes
It addresses the directives per the letter of the order; however, it is not necessarily improving reliability.
Yes
On the topic of ‘adding in’ - listing and evaluating the transmission facilities below 200 kV, we propose the inclusion of qualifications that prevent the consideration and evaluation of irrelevant facilities (e.g. facilities that are not tripped by the applicable relay settings).
No
We agree that the topics of generator relay loadability and power swing protective relaying should be referred to in other separate standards. While we acknowledge that it is in everyone’s best interest to respond to the FERC directives, there are numerous technical flaws that need to be resolved in their request. Forming a team and spending considerable resources will not gain industry acceptance to these directives.
No
No
Individual
Tribhuwan Choubey
Southern California Edison
No
Applicability clause 4.12 and 4.14 - Formulating a consistent methodology test to determine for a sub 200KV facility by the Planning Coordinator is quite an uphill task keeping in view the different circuit configuration different utilities may have. It is best left alone to each utility to determine the facilities which can be a candidate for inclusion as a bulk power system. The current risk based assessment criteria to determine bulk power facility should be continued.
No
Requirement R1.7, R1.8, R1.13 do not provide a clear guideline on generators connected to the load center on Radial basis, where load current into the generators (forward direction current seen by the relay) is just an auxiliary load and insignificant compared to the transmission line rating.
No
The relay if set according to Requirement R1.2 are based upon 15 minute highest seasonal facility loading duration. This gives sufficient time for the operators to take manual corrective action, if the deem so. There is no need for the Registered entity to provide a list, as it would not be efficient and cost effective.
Group
PSEG Companies
Kenneth D. Brown
No
In attachment A was added a new requirement, item 1.6. We not agree with this. Sometimes these elements have to be set lower than the criteria. As long as the protection system as a whole does not trip the line, then that should meet the criteria. Individual elements that supervise tripping element should NOT be part of the standard.

No
No
Individual
Dale Fredrickson
Wisconsin Electric
No comment
No comment
No comment
No comment
No comment
No comment
No
We strongly disagree with this change. Applying the loadability requirement to supervisory functions in protection system will have an extremely negative effect on BES reliability. With this change, protection systems will be less dependable, resulting in increased probability of a failure to detect a system fault. This change should not be implemented.
No comment
No comment
No comment
No comment
No
No
Group
PacifiCorp
Sandra Shaffer
Yes
Yes
Yes
Yes
Yes
No
Paragraph No. 264 directs a revision to Section 1 of Attachment A in order to include supervising relay elements. This change as currently written requires further clarification to meet this directive. For example, a Distance element is commonly supervised by a phase overcurrent element (Fault detector). If this change suggests that the overcurrent element has to be set above maximum load, then PacifiCorp disagrees with the modification. The fault detector will not trip the line by itself; it operates to qualify the distance element assertion. It is our standard practice to set this element above load where possible, but without restricting the reach of the distance element. This means that if the fault current at the maximum reach of the distance element is below load, setting the fault detector above load will restrict the reach of the distance element- this would compromise the protection scheme. In microprocessor relays where Load encroachment is used this is even more critical. The Load encroachment function will prevent the distance element from operating in the load region and a fault detector setting that is sensitive enough can be used safely without the need to set it above load current to enhance the distance element reach.
Yes
No
No
It is very difficult to comment on test parameters that have not been determined.

No
No
Group
Southern Company
Andy Tillery
Yes
Yes
Yes
Yes
Yes
Yes
No
The language that has been added to PRC-023 related to the inclusion of protection elements (fault detectors) supervising protection functions that are subject to the PRC-023-2 requirements is not appropriate and will likely decrease the reliability of the BES for the following reasons: - The tripping logic utilizing these elements is an AND function, it takes distance element AND the fault detector (FD) to trip. Since all distance elements meet the loadability criteria, it is not necessary to also ensure FD meet hese requirements. - Setting FD above nominal load point would unnecessarily reduce sensitivity of distance element and in many cases eliminate the distance element's ability to protect the very system element it is designed and intended to protect - It would require very expensive communications based relay schemes to replicate this lost protection if it is even possible to do so; a long radial line is one instance where it would not be possible - Eliminating the FD would actually reduce Security and Dependability in electromechanical schemes - There is a whole generation of microprocessor based relays that it is not possible to eliminate the FD; to effectively take it out of service, one would have to set it to the most sensitive setting which would violate the loadability criteria - Relays at terminals with high SIR, a weak source system, and line with large conductors where the far end fault current may be smaller than maximum line current (similar to Exception 6 of the Relay Loadability Exceptions: Determination and Applications of Practical Relaying Loadability Ratings, Version 1.1 published November 2004 by the System Protection and Control Task Force of NERC) - Faults with low power factor could present a similar magnitude of line current as normal high power factor load currents
Yes
Yes
No
Yes
No
No
Group
Bonneville Power Administration
Denise Koehn
Yes
No
The modified Requirement R1 requires that one of the 13 criteria be used to prevent out-of-step blocking schemes from blocking tripping for fault conditions. The problem is that the 13 criteria are only related to loading conditions, and it is not clear how they would be applied to prevent out-of-step blocking schemes from blocking a trip during a fault, or if it is even possible to use these criteria for this purpose. The modified Requirement R1 requires actions that are ambiguous and we cannot support it as written.
No
In some cases, Section 10 of Requirement R1 would be impossible to meet. For example, a 150/200/250 MVA, OA/FOA1/FOA2 transformer is required by Section 10 to have its protection set so that it doesn't operate at or below 150% of the maximum transformer rating of 250MVA, or 1.5x250=375MVA. The modified Section 10 would also require

that the protection not expose the transformer to a fault level and duration that exceeds its capability. According to IEEE C37.91, a through-fault of two times the transformers base rating, 2x150=300MVA, will be damaging to the transformer. For this particular transformer, which is not unusual, Requirement R1, Section 10, requires the protection to operate for through faults of 300MVA or greater, but not operate for loads of 375MVA or less. It is impossible to simultaneously meet both of these conditions, so Section 10 is unacceptable. One possible way to correct the problem is to change the requirement so that the protection does not operate below 200% of the transformer base rating. This would allow the protection to meet IEEE C37.91 for through-faults and still allow overloading of the transformer.
This change adds an additional burden to the applicable entities, but serves no purpose other than to satisfy FERC's misinterpretation of what a fifteen-minute facility rating is.
No
Requirement R5 is okay, but Part 5.1 adds an additional and useless extra burden to the applicable entities. The process that the Planning Coordinator is required by this part to have would almost certainly be to simply apply the criteria in Attachment B to lines and transformers operated below 200kV to determine if they are critical to the BES. Requiring documentation for such a trivial process results in increased paper work, additional preparation for an audit, and is a waste of everyone's time. We suggest deleting Part 5.1.
No
Here we have a situation where the standard is being compromised to satisfy FERC's misunderstanding of what a supervising relay is. In Paragraph 266, FERC gives an example of how a line differential relay works in an attempt to demonstrate why supervisory elements must not operate for load, but instead they clearly demonstrate their misunderstanding of the details of differential relay operation and what a supervisory relay is. Modern differential relays will disable the differential function upon loss of communications. If an overcurrent element is present, it would be used for backup protection, not as a supervisory element. If an overcurrent element were used to supervise a differential element, the sensitivity of the differential relay would be lost and the result would be a simple overcurrent relay. FERC's misunderstanding has resulted in the improper addition of supervisory relays in Attachment A, Section 1. Sometimes supervisory relays must be set below maximum loading to obtain the purpose they were intended for. For example, it is often necessary to set overcurrent supervision of distance relays below the maximum load current of the line so that they will operate for remote faults. This modification to Attachment A would prohibit that action and make it impossible to set the supervisory relays to comply with the standard and still provide adequate protection. The modification to Attachment A is unacceptable.
5.1.2 and 5.1.3 both apply to the same systems and should be combined into one sub-requirement. Also, since the date of the applicable regulatory approval is now established, please consider replacing the cryptic phrase "at the beginning of the first calendar quarter 39 months following applicable regulatory approval" with an actual date.
Yes
No
Yes
No
No
Individual
Kathleen Goodman
ISO New England Inc.
No
We believe this directive needs to be addressed by a full standards drafting team to ensure the precise language is crafted to adequately address the directive. Furthermore, we believe only the full standards drafting team could identify equally effective alternatives to the Commission's directives as they have made clear they allow in this Order and many others. Some immediate concerns with the proposal include: 1) Our understanding is that the application of NERC standards is limited to the BES. Thus, facilities below 100 kV must be included in the Regional Entity definition of BES to be eligible. The requirements should reflect this. The way the proposed standard reads, one might conclude the PC must test every facility below 100 kV. This surely can't be the intent. 2) Furthermore, the directive appears to require some action on the Regional Entities. From paragraph 60, "We also direct that additions to the Regional Entities' critical facility list be tested for their applicability to PRC-023-1 and made subject to the Reliability Standard as appropriate." It is not clear how this directive is reflected in the standard to ensure that this work is completed prior to the PC's performing their assessment for below 200 kV facilities. The bottom line is that the changes here are significant enough that they would benefit from a group of experts reviewing the directives and proposing the precise language that is needed.
No
Requirement R1, Parts 7, 8 and 9: Requirement R1, Parts 7, 8 and 9, replace the phrase "under any system configuration" with "under any system condition:" 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 systemcondition. 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 systemcondition. 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 [ ] to the under any system condition. [Brackets added, also see further comment on missing wording following]

This phrase "under any system configuration" could be construed as being too all-inclusive, as one could postulate multiple events, e.g., simultaneous outages, which however unlikely could permit power flows in a direction for which the system was not originally designed. As with the second comment below, the phrase "under any system condition" was part of Revision 1 and is unchanged by Revision 2, however, the new applicability to below 200 kV creates the new concern. Requirement 1, part 9: As currently written, Requirement 1, part 9 states: 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 [___] to the under any system configuration. [Brackets added] Some words are missing. The brackets have been added above to show one place where at least some of the needed wording may be missing. A rewrite is necessary in order for this sentence to make any sense.
Yes
No
We do not understand the need for this directive or requirement. A relay that is set to operate at 115% greater than the 15-minute rating of the facility does not equate to damage occurring on that facility if operated at that point in 15 minutes. Furthermore, it does not mean the relay will operate in 15 minutes nor does it mean the operator has only 15 minutes to take action. In fact, the operator may have less time depending on the time delay set on the relay. It is no different than any other relay. Usually, the facility will be operated with some buffer so that there is no chance that an entity could trip the facility due to loading above the relay limit. In fact, the transmission operator should be aware of any relay that might be the limiting facility so they can operate the facility with some margin of error to ensure they don’t inadvertently cause a relay operation due to loading.
Yes
Yes
Yes
No
While we agree removing the footnote is straight forward and addresses one Commission directive. In particular, we believe that only a full drafting team could adequately assess if any additional time will be needed to comply with the standard for sub-100 kV facilities particularly when we consider there are some outstanding issues a regional entities critical facilities list identified in Question 1. Also, we are unable to assess if the two directives are fully addressed absent a proposed implementation plan.
Yes
No
We are not prepared at this time to offer equally efficient and effective alternatives. Rather, we believe this is the purpose for convening a full drafting team and that the drafting team should propose their alternatives.
No
We largely believe the scope will allow the drafting team to address the directives. However, we request that the scope be modified to make clear that the drafting may use equally effective alternatives to address the Commission’s directives per the Commission in this order and other orders such as Order 693. The scope should address apparent conflicts in the timing of requirements posed by the standard. It is our understanding that, based on the final date afforded NERC to develop the criteria for the determination of sub-200 kV facilities,a newly proposed implementation plan will be offered to allow the Planning Coordinators an appropriate time frame to apply the criteria to determine the “critical” facilities below 200 kV. The implementation plan should cause the effective date for circuits described in 4.1.2 and 4.1.4 to be changed from “39 months following applicable regulatory approvals” to a date linked to the Planning Coordinators schedule to provide a list to its TOs, GOs and DPs.
No
We are not aware of any regional variances per se. However, each regional entity has its own definition for BES and this needs to be considered when addressing sub-100 kV facilities.
No
Individual
Robert Ganley
Long Island Power Authority
No
There appears to be a disconnect between FERC’s “sub 100 kV” and proposed “below 200 kV” revision in the Applicability Section. LIPA seeks clarification on this. Also, by whom and by which method will the criticality of the substations be ascertained?
No
Requirement R1, Parts 7, 8 and 9, replace the phrase “under any system configuration” with "under any system condition:" This phrase "under any system configuration" could be construed as being too all-inclusive, as one could postulate multiple events, e.g., simultaneous outages, which however unlikely could permit power flows in a direction for which the system was not originally designed. Requirement 1, part 9: As currently written, Requirement 1, part 9 states: 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 [___] to the under any system configuration. [Brackets

added] Some words are missing. The brackets have been added above to show one place where at least some of the needed wording may be missing. A rewrite is necessary in order for this sentence to make any sense.
Yes
Yes
No
FERC order 733 p224 requires that the list of facilities that have protective relays set pursuant to R1.12 of anticipated overload be made available to users, owners, and operators of the BPS. However, the proposed revision to R4 requires the list to be made available to Regional Entity only. Please clarify. Also, FERC order uses the term “by request” which is missing from the proposed revision.
No
LIPA understands the drafting team’s rationale, however, believes that the proposed method in Attachment B should be developed before providing comments.
No
LIPA believes that the new wording in 1.6 Attachment A is unnecessary since the existing wording already complies with the FERC order p.264. Supervisory functions are already part of the protective functions 1.1 through 1.5. Also, this new wording will be subject to varied interpretation and create more confusion.
No
Yes
Yes
Involving industry working groups such as IEEE, EPRI, etc who have proven technical experts will also help in effectively achieving reliability.
Yes
LIPA agrees with the scope in general. Please consider our comments above for answers to specific issues.
Yes
NPCC BPS definition based on A10 criteria is a regional variance.
No
Individual
Kirit Shah
Ameren
No
Attachment B as mentioned in R5 is not available for review.
Yes
No
The language is not clear. It appears that the transmission line relays are being used as the thermal overload protection for the transformer.
Yes
No
See our response to Question 1
No
In attachment A – 1.6 is not a tripping function – it’s a supervisory function – it in itself does not trip which is the description of ‘1’ therefore needs to be elsewhere if kept.
Yes
No
No
Individual
Thad Ness
American Electric Power

No
AEP understands the intent of the FERC Order (Paragraph 60) to address the sub-100 KV facilities only if they are associated with critical facilities above 100 KV. The applicability and the associated requirements should be reworded to ensure that the Planning Coordinator does not have to identify critical facilities below 100 KV.
Yes
Yes
Yes
Yes
No
Please refer to our comment under question number 1. AEP reserves the right to provide additional comments once Attachment B has been drafted and supplied for industry review.
No
AEP requests some clarifying information regarding what is envisioned for 1.6 of Attachment A.
No
It is unclear how much time a TO, GO, or DP would have to implement the changes based on the results of the analysis by the Planning Coordinator. In addition, the Effective Date section is a one-time event upon regulatory approval. What are the on-going implementation expectations? There should be some allowed lead beyond initial implementation after facilities are identified by the Planning Coordinator.
No
Refer to our comment under question 1.
No
Not at this time, but AEP would like to consider all viable options throughout the standard development process.
Yes
No
No
Individual
Michael Moltane
ITC Holdings
Yes
No
The proposed wording seems out of place in this requirement and is not clear as how it is being applied to subrequirements 1 - 13
No
R1 -10 is all about loadability of the relays protecting the transformer. If the requirements of R1-10 cannot be met without exceeding the transformer damage curve, then we go to R1-11. We do not feel that there should be anything to do with fault duty.
Yes
Yes
Yes
No
It appears from the new 1.6 (Attachmnt A) that fault detectors must meet loadability requirements. These do not trip and must not be included in PRC023. We will not be able to adequately protect longer lines in weak areas with this requirement in place.
No
The new effective dates for 5.1.2 will for the most part be ok. Some of these below 200 kV lines will have to be reconstructed to be able to have adequate protection and meet the required loadability. It will be difficult to do this in 39 months. We suggest a mitigation program be required for those lines that will be difficult to meet the 39 month deadline.
Yes
No

No
Several parts of the standard go too far (Appendix A R1.10) and will require us to document faults and clearing times to prove the fault duty of transformer connections. Also the requirements to deal with out of step blocking relays should go in phase 3 and not in this standard.
: Utilities with long lines and in weak areas will have difficulty protecting their lines and meeting the required loadability. Regions where there are very rural systems will want to write standards that allow adequate protection for their systems.
No
Group
FirstEnergy
Doug Hohlbaugh
Yes
Yes
No
Although it is true that the FERC directive specifically states "limiting piece of equipment" their reasons and justifications all involve transformers. We propose replacing "limiting piece of equipment" with "transformer" would meet the FERC's reliability concern as well as provide clarity to applicable entities. We believe this is an equally effective means of meeting the directive.
No
We suggest removing the Regional Entity from the list of entities receiving this information since they do not have a reliability-related need for it.
Yes
Yes
Although we agree that R5 is the appropriate requirement to reference the criteria to be used, it is still to be determined if we agree with the criteria since it is still being developed.
No
FirstEnergy supports applying PRC-023 to certain supervising relays, such as overcurrent relays that are enabled only when another (usually communications based) scheme is out of service, or overcurrent relays that are ANDed with current differential elements that can trip by themselves if the communications path used by the current differential scheme is compromised. However, it is not clear that a 150% factor is the correct one to use in this case. Our understanding is that 150% is a combination of an error factor (widely utilized by industry) of 15% plus a 35% margin to approximate a 15 minute interval rating to give operators time to react to adverse system conditions. It is unclear that this extra 35% margin is needed for these supervising relays, when the reliability goal is to prevent relays being continuously picked-up. We recommend that the standard utilize a 115% margin (rating duration nearest 4 hours) for these types of supervising relays and that this would be adequate to meet the Commission's stated reliability concerns. However, there are several other types of schemes that utilize supervising relays where applying PRC-023 would be detrimental to the reliability of the bulk power system. One widely used case is the supervision of an impedance relay when there is no communications scheme involved. There are cases where an impedance element/relay which is set per PRC-023, correctly operates for a fault it is intended to see, but that the actual current value will be on the order of the line rating, which will result in the scheme not operating if the supervising relay is set as the commission proposes. The alternative for these types of schemes is to remove the supervision from the scheme, which will result in the scheme operating purely on the impedance element, which is exactly the reliability concern that the Commission is trying to address with this directive. However, many microprocessor relays have inherent overcurrent supervision of impedance elements which cannot be disabled, adding to the complexity of the issue. Since this is a fairly complex theoretical/technical issue, we recommend that the NERC System Protection and Control Subcommittee (SPCS) investigate this issue and produce a white paper or other document describing any unintended consequences of implementing the FERC directive. The work of the SPCS could also consider equally effective alternatives to meeting the Commission’s directive.
Yes
No
i. The SAR shows the directive from P. 162 as part of Phase I to be implemented by March 18, 2011. However, this directive should be included in Phase III since it deals with the subject of relay operations due to power swings. ii. The directive from P. 224 is missing from the detailed section of the SAR, but is included in the table in the back of the SAR. iii. As mentioned in our response to Question 7, we do not agree with how the project is proposing to address the P. 264 directive.
No
Regarding the direcive of Par. 264, since this is a fairly complex theoretical/technical issue, we recommend that the NERC System Protection and Control Subcommittee (SPCS) investigate this issue and produce a white paper or other document describing any unintended consequences of implementing the FERC directive. The work of the SPCS could also consider equally effective alternatives to meeting the Commission’s directive.
Yes
We agree that this standards action is necessary to meet the FERC directives, but have some concerns as we have stated

in previous responses above.
No
No
Group
TSGT System Planning Group
Bill Middaugh
Yes
No
We suggest that the added phrase be removed from R1 and a new requirement created. Suggested wording is “Protection Systems that block for stable swings or out-of-step conditions shall be evaluated to ensure that appropriate tripping will occur for in-section faults that occur during the condition. Some additional delay may be required and is acceptable to ensure that the appropriate tripping occurs.”
Yes
No
We think that the data needs to be given only to the Transmission Operators, which is what FERC Order No. 733 requires. We also believe that an initial submittal is sufficient until any responsible entity begins or stops using Requirement 1, Setting 2 for setting a phase protective relay that is used to protect an applicable facility. There is no need for periodic duplicate submittals.
No
FERC Order No. 733 requires the settings be provided upon request and no initial or periodic submittal is required.
No
While we agree that the purpose of Requirement R5 is beneficial, there is much confusion about registration and responsibilities of Planning Coordinators. Though the FERC order proposes that planning coordinators perform the test developed herein, there is also flexibility in how NERC can achieve the same result. We believe that the Regional Entity (or the Reliability Coordinator, as was included in the System Protection and Control Task Force recommendation) should be the responsible functional entity for determining which elements operated at less than 200 kV need to meet Requirement R1. The Region was responsible for determining operationally significant facilities during the “Beyond Zone 3” process.
Yes
As we interpret the changes to Attachment A they are acceptable. However, there appears to be uncertainty about the intent of the drafting team. We interpret the change to 1.6, in conjunction with 2.1, to allow setting impedance relay fault detector supervisory elements at levels below load current levels. This understanding comes from the realization that the fault detector elements by themselves do not “trip with or without time delay, on load current,” a requirement described in 1. The fault detector elements can cause tripping on their own, but only for conditions of loss of potential or loss of communications, which are both excluded from the loadability requirements as steted in 2.1. If Tri-State’s interpretation of the intent of Attachment A, Sections 1, 1.6, and 2.1 is incorrect, then we do not agree that this is an acceptable and effective method of meeting this directive. There are many protection system locations in our system that require the fault detector supervision elements to be set below load current levels in order for backup impedance relays to operate securely in the event of loss of potential and to operate dependably for remote faults that inherently have low fault current magnitudes.
Yes
No
As stated in our earlier comments, we believe that some proposals exceed the directives. It is also not clear how p 162 was addressed in PRC-023-2 as indicated on SAR-3.
Yes
We included specific proposals in our comments to questions 2, 4, 5, and 6.
Yes
We agree that the scope meets the FERC directive, but some of the proposals in the proposed standard reach beyond the directive.
No
No
Individual
Yes
Yes
Yes

Yes
Yes
Yes
No
Removal of exclusion 3.1 in Att. A, will lead to reduced reliability because an operational decision to open breakers will be needed for loss of potential conditions. The corollary would be leaving the element in service with fast tripping enabled for a fault until the loss of potential condition can be diagnosed and corrected.
Yes
Yes
No
No
Removal of exclusion 3.1 in Att. A, will lead to reduced reliability because an operational decision to open breakers will be needed for loss of potential conditions. The corollary would be leaving the element in service with fast tripping enabled for a fault until the loss of potential condition can be diagnosed and corrected.
No
No
Individual
Laura Zotter, Steve Myers
ERCOT ISO
The entities who receive the list of facilities should be the same from R3 to R4.
The entities who receive the list of facilities should be the same from R3 to R4.
No
ERCOT ISO respectfully asserts that the changes in this standard need more thorough discussion. This standard is incomplete without the Attachment B and the intent of the requirements is not explicitly clear. A standard drafting team (not a SAR SDT) needs to develop Attachment B through discussion of the entire process that will meet Order 733 directives. Attachment B is a critical component needed to assess R5 and provide further feedback. Requirement 5 needs to be reworded for clarity. The standard drafting team assigned to this project needs to work closely with the Reliability Coordination SDT (Project 2006-06), which is tasked with defining critical facilities or identifying criteria for developing a list of critical facilities. ERCOT ISO disagrees with the use of the phrase ‘facilities that are critical’ in this requirement. A requirement to create a list of critical facilities should not be addressed in this standard.
ERCOT ISO thinks a standard drafting team can evaluate the Order 733 directives, work in conjunction with other Standard Drafting Teams already addressing some aspects of critical facilities, may be able to more succinctly arrive at an equally efficient and effective method of achieving the intent of the directive(s). The coordination between teams is vital to avoid confusion and possible overlap.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
No
This requirement needs to be refined to clearly state the intent. It is unclear if “limiting piece of equipment” is referring to just transformers or other elements. Some of the elements involved in the construction of a transmission line/transformer arrangement such as line conductors, etc. may not have published fault current ratings. It is unclear how to determine the most limiting piece of equipment if published fault current ratings are not available for these devices

No
Item 1.6 of Attachment A needs to be clarified. If the intent is to include protective functions such as fault detectors then this could possibly lead to relay sensitivity problems when switching contingencies create weaker systems than normal and a line is faulted. It is unclear why supervisory functions are considered if the protective functions they supervise will operate in compliance with R1
Individual
Jon Kapitz
Xcel Energy
Yes
Yes
Yes
Yes
Yes
Yes
No
Xcel Energy disagrees with the inclusion of the supervising functions in part 1.6 of Section 1 in Attachment A. Supervising functions in protection schemes provide security for non-power system fault events and are not the principal elements for scheme operation. Only principal elements should be considered in the requirements of the PRC-023 standard. Functions such as overcurrent fault detectors provide security in the event of a failed potential source or blown secondary fusing. Fault detectors must be set below the minimum end-of-zone fault with a single system contingency in effect. It is common industry practice to set these functions at 60-80% of these minimum fault levels and may necessitate a setting that is below the Facility Rating of a circuit. Increasing the setpoint of an overcurrent fault detector above the Facility Rating will limit the coverage of the protection system and may impact the system’s ability to protect the electrical network from Faults. An alternative is to limit the Facility Rating as allowed in Requirement R1.12. However limiting this Facility Rating places an arbitrary constraint on the circuit and is not justifiable for a non-principal function. Eliminating the fault detector is not possible in the case of some microprocessor-based relays and if it is possible, reduces the security of the protective scheme.
Yes
Group
IRC Standards Review Committee
Ben Li
No
We believe this directive needs to be addressed by a full standards drafting team to ensure the precise language is crafted to adequately address the directive. Furthermore, we believe only the full standards drafting team could identify equally effective alternatives to the Commission’s directives as they have made clear they allow in this Order and many others. Some immediate concerns with the proposal include: 1) It is not clear what a “critical facilities list identified by the Regional Entity” is as specified within the order so addressing the directive is a challenge. This standard is not the appropriate venue for development or consideration of a critical facilities list. There is a supplemental SAR in process for the Reliability Coordination project that is to address that topic. 2) Our understanding is that the application of NERC standards is limited to the BES. Thus, facilities below 100 kV must be included in the Regional Entity definition of BES to be eligible. The requirements should reflect this. The way the proposed standard reads, one might conclude the PC must test every facility below 100 kV. This surely can’t be the intent. 3) Furthermore, the directive appears to require some action on the Regional Entities. From paragraph 60. “We also direct that additions to the Regional Entities’ critical facility list be tested for their

applicability to PRC-023-1 and made subject to the Reliability Standard as appropriate." It is not clear how this directive is reflected in the standard to ensure that this work is completed prior to the PC's performing their assessment for below 200 kV facilities. This standard is not the appropriate venue to determine or revise a critical facilities list, nor is it appropriate for a Regional Entity to establish such a list. The bottom line is that the changes here are significant enough that they would benefit from a group of experts reviewing the directives and proposing the precise language that is needed.
No
We believe this directive needs to be addressed by a standards drafting team to ensure the precise language is crafted to adequately address the directive. Furthermore, we believe only the full standards drafting team could identify equally effective alternatives to the Commission's directives as they have made clear they allow in this Order and many others.
No
We believe this directive needs to be addressed by a full standards drafting team to ensure the precise language is crafted to adequately address the directive. Furthermore, we believe only the full standards drafting team could identify equally effective alternatives to the Commission's directives as they have made clear they allow in this Order and many others. Additionally, we question if this directive should be addressed in the FAC standards rather than in PRC-023.
No
We do not understand the need for this directive or requirement. A relay that is set to operate at 115% greater than the 15-minute rating of the facility does not equate to damage occurring on that facility if operated at that point in 15 minutes. Furthermore, it does not mean the relay will operate in 15 minutes nor does it mean the operator has only 15 minutes to take action. In fact, the operator may have less time depending on the time delay set on the relay. It is no different than any other relay. Usually, the facility will be operated with some buffer so that there is no chance that an entity could trip the facility due to loading above the relay limit. In fact, the transmission operator should be aware of any relay that might be the limiting facility so they can operate the facility with some margin of error to ensure they don't inadvertently cause a relay operation due to loading.
No
The objective of R4 as written is unclear and does not conform with the results-based concept in that it does not clearly specify a reliability directive. We suggest removing this requirement altogether as we do not believe this should be an on-going enforceable requirement. Rather, we think it makes more sense for NERC to use section 1600 of its Rules of Procedure to request the data. We believe that NERC and the Commission will likely determine that they don't need to continually receive this data after reviewing it the first time. Nothing in the directive indicates this must be accomplished through a standard. If NERC and FERC do identify a continuing need for the data, the standard could be modified at a later date.
No
We disagree with modifying the requirement until the criteria is identified. Modifying the requirement now presumes the criteria will have no impact to the requirement. Contrarily, we believe that the criteria may cause some change to the requirement as well. The criteria in Attachment B along with any necessary modifications to the associated requirement should be developed by a full standards drafting team. Only the full standards drafting team could identify equally effective alternatives to the Commission's directives as they have made clear they allow in this Order and many others.
No
We believe this directive needs to be addressed by a full standards drafting team to ensure the precise language is crafted to adequately address the directive. Furthermore, we believe only the full standards drafting team could identify equally effective alternatives to the Commission's directives as they have made clear they allow in this Order and many others.
No
While we agree removing the footnote is straight forward and addresses one Commission directive, we believe the other directives need to be addressed by a full standards drafting team to ensure the precise language is crafted to adequately address the directives. Furthermore, we believe only the full standards drafting team could identify equally effective alternatives to the Commission's directives as they have made clear they allow in this Order and many others. In particular, we believe that only a full drafting team could adequately assess if any additional time will be needed to comply with the standard for sub-100 kV facilities particularly when we consider there are some outstanding issues including a regional entity's critical facilities list identified in Question 1. Also, we are unable to assess if the two directives are fully addressed absent a proposed implementation plan.
No
We largely believe the scope will allow the drafting team to address the directives. However, we request that the scope be modified to make clear that the drafting team may use equally effective alternatives to address the Commission's directives per the Commission in this order and other orders such as Order 693. There is a discrepancy between the entities listed in the Applicability Section and those checked off in the SAR. The latter indicates that the SAR is also applicable to the Reliability Coordinator, which we do not believe is appropriate.
No
We are not prepared at this time to offer equally efficient and effective alternatives. Rather, we believe this is the purpose for convening a full drafting team and that the drafting team should propose their alternatives.
No
We largely believe the scope will allow the drafting team to address the directives. However, we request that the scope be modified to make clear that the drafting team may use equally effective alternatives to address the Commission's directives per the Commission in this order and other orders such as Order 693.
No
We are not aware of any regional variances per se. However, each regional entity has its own definition for BES and this needs to be considered when addressing sub-100 kV facilities.
No

Group
MRO's NERC Standards Review Subcommittee
Carol Gerou
No
However, this response is conditional depending on whether the criteria that will be established within Attachment B (see R5.1) are reasonable and apply to properly qualified facilities below 200 kV.
Yes
No
The word change meets the strict interpretation of the directive, but it is not necessarily improving the reliability of the system. Faults are cleared in cycles and transformer damage curves do not start until at least one second.
Yes
No
While achievable, this will not come without effort and does not necessarily improve the reliability of the BES commensurate with the compliance burden.
No
As noted in Q1 above, a response would be conditional and depend on whether the criteria that will be established within Attachment B (see R5.1) are reasonable and apply to properly qualified faculties below 200 kV. In addition, the R5 requirement should include wording that limits the scope of the transmission facilities (line and transformer circuits) to be evaluated to only those transmission facilities that can be tripped by the relay settings subject to requirement R1. Requirement R5 should also qualify that only the transmission facilities that are “known” to be associated with the relay settings subject to requirement R1 need to be evaluated. If the SDT wants to better assure that the Planning Coordinator knows about all of the pertinent transmission facilities, then they should add a requirement that obligates Transmission Owners, Generator Owners, and Distribution Providers to provide the Planning Coordinator with a list of the transmission facilities that are associated with the relay setting subject to requirement R1.
No
In Order 733, the Commission cites in footnote 186 (p. 161) the definitions of dependability and security, two components of reliability for protective relays. The Commission did not recognize that the two tend to be mutually exclusive. Raising dependability (making sure breakers trip during a fault) can sacrifice some degree of security (tripping more than is needed). Historically, protection engineers have been biased toward dependability to ensure the safety of people and equipment. The exclusions allow that to happen. These are contingency scenarios where protective schemes are compromised. For a second contingency, the dependability is at risk if fast tripping is not employed. By removing the exclusion, reliability could be negatively jeopardized. For example, an operational decision to open breakers will be needed for loss of potential. The corollary would be leaving the element in service with fast tripping enabled for a fault until the loss of potential condition can be diagnosed and corrected.
Yes
No
It addresses the directives per the letter of the order; however, it is not necessarily improving reliability.
Yes
On the topic of ‘adding in’ - listing and evaluating the transmission facilities below 200 kV, we propose the inclusion of qualifications that prevent the consideration and evaluation of irrelevant facilities (e.g. facilities that are not tripped by the applicable relay settings).
No
We agree that the topics of generator relay loadability and power swing protective relaying should be referred to in other separate standards. While we acknowledge that it is in everyone’s best interest to respond to the FERC directives, there are numerous technical flaws that need to be resolved in their request. Forming a team and spending considerable resources will not gain industry acceptance to these directives.
No
No
Group
Dominion Electric Market Policy
Mike Garton
No
It depends on what Attachment B (R5.1) requires once it is developed. Without knowledge of the final content developed for Attachment B, we do not support this.
Yes
No
The requirement is not clear. For example, how do we determine and verify the limiting piece of equipment under fault conditions? It might be a splice or a jumper. Since the document refers to duration, this seems to apply mainly to

transformer overcurrent relaying which would be for overload protection not fault protection that has no intentional delay.
Yes
Yes
Yes
No
Dominion disagrees with the directive to the ERO to revise section1 to include supervising relays for example, the fault detectors that we have in electromechanical distance schemes. The impedance relays are set to meet Reliability Standard PRC-023-1 while the overcurrent fault detector does not trip the transmission line breaker(s) independently of the impedance relays. Simultaneously meeting full allowance of the line terminal emergency loading limit and providing adequate sensitivity for detecting line faults with this fault detector will simply not be achievable for many of our lines.
Yes
Yes
No
Yes
No
No
Since there is no question that asks if there are other concerns with this draft, I will add one here….. R2 should be modified to read " The Each Transmission Owner, Generator Owner, or and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, Settings1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall forward this information to the Planning Coordinator, Transmission Operator, and Reliability Coordinator. The burden for acknowledging agreement or specifying reasons for disagreement should reside with the Planning Coordinator, Transmission Operator, and Reliability Coordinator. Suggest SDT develop additional requirements similar to those in FAC-008 @ R2 and R3.
Individual
Greg Rowland
Duke Energy
Yes
Yes
No
R1.10 has added the requirement that protection settings can't expose transformers to fault levels and durations that exceeds its capability, while at the same time not operate at or below 115% of highest emergency rating. We would argue that an overcurrent relay cannot be set to satisfy both requirements. A transformer's through-fault protection curve (C37.91) begins at 200% of the transformers self-cooled rating. The highest emergency rating is commonly 150% (or higher) of the transformer's highest (cooled) rating. Overcurrent relays could not be set to coordinate with both the damage curve and the overload rating.
Yes
Yes
Paragraph 224 addresses R1.12, requiring documentation and making available a list of facilities that have protective relays set pursuant to R1.12. Although Order 733 was silent on R1.13, should the new R4 not also apply to R1.13?
No
We don't have Attachment B yet, and the standard development timeline has the standard being submitted to FERC in March of 2011, which we believe is an unreasonable timeline.
No
Attachment A has added 1.6 stating "Protective functions that supervise operation of other protective functions" is included in the standard. We would argue that it is not reasonable to include overcurrent fault detectors used to supervise distance elements or breaker failure schemes. These relays provide security to the protection scheme, such as for loss of potential conditions, and do not trip on their own. If these relays would be set per the standard, it would render the schemes ineffective for many fault conditions. In the case of electromechanical schemes, the supervising relay could be removed from service which could make the protection scheme misoperate. In the case of microprocessor relays, the supervising relay is embedded in logic and can't be removed.
No
Until we see the criteria for Attachment B, we can't agree that 39 months is sufficient time.

Yes
No
No
• The SAR states that Paragraph 162 is part of Phase I, but the new standard addressing stable power swings is Phase III.
No
No

Consideration of Comments on Revisions to Relay Loadability for Order 733 SAR and an initial set of proposed requirements — Project 2010-13

The Revisions to Relay Loadability for Order 733 SAR Drafting Team thanks all commenters who submitted comments on the proposed SAR and an initial set of proposed requirements. The SAR and proposed standard were posted for a 30-day public comment period from August 19 through September 19, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 36 sets of comments, including comments from more than 88 different people from approximately 36 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

The Standard was posted for an “informal” comment period – the team provided a summary responses to the comments submitted on the proposed standard (Questions 1-8) and the SAR was posted for a “formal” comment period - and the team provided detailed responses to the comments submitted on the SAR (Questions 9-13)

Summary of Changes:

The SDT revised sections 4.1.2 and 4.1.4 for consistency and to refer to facilities “determined by the Planning Coordinator to comply with this standard.”

The SDT added a new 4.1.3 “Transmission lines operated below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry and are also determined by the Planning Coordinator as required to comply with this standard. "

The SDT renumbered old 4.1.3 to 4.1.4.

The SDT renumbered old 4.1.4 to 4.1.5 and reverted the voltage threshold to the original text consistent with the modification to section 4.1.2.

The SDT added "4.1.6 Transformers with low voltage terminals connected below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry and are also determined by the Planning Coordinator as required to comply with this standard."

In response to comments that Requirement R5 is confusing the SDT deleted “to prevent cascading when protective relay settings limit transmission loadability” from Requirement R5. Removing this does not change the intent of the requirement.

Commenters indicated for a variety of reasons that the requirement related to out-of-step blocking added to Requirement R1 is confusing. The SDT agrees and removed out-of-step blocking from Requirement R1. The requirement pertaining to evaluation of out-of-step blocking protection has been moved to a separate requirement (now Requirement R2) to more clearly delineate this requirement from assessment of relay loadability of phase protective relays.

Some commenters indicated that the word “settings” should be replaced throughout R1 when referring to a part, or sub-requirement of R1. The SDT modified Requirement R1 by replacing the word “settings” with “criteria.” This is consistent with the main Requirement R1 which in the presently approved standard (PRC-023-1) refers to sub-requirements R1.1 through R1.13 as criteria to prevent phase protective relay settings from limiting transmission system loadability.

Some commenters identified an error in the draft standard in criterion 9 in Requirement R1 that resulted in omitting a phrase contained in the presently approved standard. The SDT modified criterion 9 in Requirement R1 to reinsert the deleted phrase.

IEEE C37.91 Figure A5 has two components to the thermal damage curve for through-faults: the "thermal component" begins at 2x the transformer nominal nameplate rating, and seems to be the root of commenters' concerns. The "mechanical component" begins at a current equal to the reciprocal of the twice the transformer impedance. The commenters are correct in their characterization of the "thermal component" of the transformer damage curve, in that it is not possible to satisfy the posted PRC-023-2 R1, criterion 10 and also protect the transformer for currents in this region. Upon careful consideration of FERC Order 733, the SDT revised R1 criterion 10 to reference only the mechanical withstand capability.

Many commenters questioned the inclusion of "limiting piece of equipment" rather than "transformer", as the fault-withstand capability of terminal equipment (switches, breakers, current transformers, etc) may be unavailable. Upon further consideration of FERC Order 733, the SDT modified criterion 10 by replacing "limiting equipment" with "transformer."

The SDT modified the wording of R4 as follows. "Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to utilize Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide...." as a result of comments.

The SDT agreed to remove the Regional Entity from the list of entities receiving this information in Requirement R4.

One commenter noted that the SDT needs to work closely with the Reliability Coordination SDT (Project 2006-06) which is tasked with defining critical facilities or indentifying criteria for developing a list of critical facilities. The commenter disagreed with use of the phrase "facilities that are critical" in this requirement and cautioned that a requirement to create a list of critical facilities should not be addressed in this standard. The SDT notes that although the phrase "critical to reliability of bulk electric system" appears in the approved PRC-023-1 and is used in Order No. 733, the SDT recognizes that use of the same or similar terms in multiple standards will result in confusion. Use of the phrase "critical to reliability of the Bulk Electric System" in PRC-023 is intended to have meaning specific to the issue of relay loadability; specifically to identify facilities, that if they trip due to relay loadability following an initiating event, may contribute to undesirable system performance similar to what occurred during the August 2003 blackout. The SDT has modified the standard to replace the phrase "critical to the reliability of the bulk electric system" with "that must comply with this standard." The SDT believes this will avoid potential confusion and that reliability will be adequately addressed because the criteria in PRC-023 - Attachment B identify all facilities that must be subject to this standard to maintain reliability of the Bulk Electric System.

One commenter noted that Requirement R5, Part 5.1 is unnecessary since the process to use the criteria in PRC-023 - Attachment B would almost certainly be to simply apply the criteria and that requiring documentation of such a process will result in increased paperwork and additional preparation for an audit without a reliability benefit. The SDT agrees that this part of Requirement R5 is unnecessary and has removed it from the Standard.

Three-fourths of commenters believe the addition of section 1.6 in PRC-023 - Attachment A is not an equally efficient and effective method of meeting this directive. More than one-half of commenters believe that addressing the directive in the proposed manner will have a negative impact on reliability of the bulk electric system. The SDT agrees that addressing the directive in the manner proposed in the first posting will have the unintended consequence of impacting the dependability and security of certain protection systems. The SDT has revised the draft standard to address the following concerns noted by commenters.

- More than one-half of commenters noted that the proposed modification would require overcurrent fault detectors applied to supervise distance (impedance) elements to meet the relay loadability requirements which would have a detrimental impact on reliability. Setting these fault detectors to meet PRC-023 would restrict the ability of some distance elements to trip for end-of-zone faults, particularly on weak source systems. Eliminating the fault detector to avoid this concern would have the negative impact of making the protection system susceptible to undesired tripping during close-in faults on adjacent elements. Some commenters further noted that many microprocessor relays have inherent overcurrent supervision of impedance elements which cannot be disabled.

- Several commenters noted that the standard should apply to protective systems and not to individual components of protective systems and that compliance should be based on the ability of the protective system as a whole to meet the performance criteria established by the standard. Some commenters also noted that a clarification is required that “protective functions” applies only to those protective relay elements that would respond to non-fault or load conditions and could issue a direct trip.

- Some commenters noted their belief that the modification goes well beyond the Commission’s concern and they proposed alternatives they believe would be equally effective and efficient approaches to addressing the Commission’s reliability concerns.

In response to these concerns, in particular the negative impact on reliability associated with the proposed modification, the SDT has modified section 1.6 to include “1.6. Supervisory elements associated with current based communication assisted schemes where the scheme is capable of tripping for loss of communications.” The SDT also modified the second bulleted item in section 2.1 to add the clause, “except as noted in section 1.6 above.”

The SDT agrees with several commenters about the proposed language for Effective Dates and has changed the language to the following:

5.1. Requirement R1: the first day of the first calendar quarter after applicable regulatory approvals, except as noted below.

5.1.1 For the addition to Requirement R1, criterion 10, to set transformer fault protection relays and transmission line 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, the first day of the first calendar quarter 12 months after applicable regulatory approvals.

5.1.2 For supervisory elements as described in Attachment A, section 1.6, the first day of the first calendar quarter following 24 months after applicable regulatory approvals.

5.2. Requirements R2 and R3: the first day of the first calendar quarter after applicable regulatory approvals.

5.3. Requirements R4 and R5: the first day of the first calendar quarter following 24 months after applicable regulatory approvals.

5.4. Requirement R6: the first day of the first calendar quarter 18 months after applicable regulatory approvals.

5.5. Requirement R7: the first day of the first calendar quarter after applicable regulatory approvals.

To address the need for entities to meet the requirements of the standard for facilities identified by the Planning Coordinator in the future, the SDT added a new requirement (R7).

Several commenters indicated that the directive from P. 224 is missing from the detailed section of the SAR, but is included in the table in the back of the SAR. This was an error in the SAR and the SDT has added this directive to the detailed section of the SAR for Phase I. The new Requirement R5 will support collection of the data necessary for the ERO to address the directive. The ERO will provide the data upon request, but outside of PRC-023.

http://www.nerc.com/filez/standards/SAR_Project%202010-13_Order%20733%20Relay%20Modifiations.html

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, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.1

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

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	10									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	NY State Reliability Council	NPCC	10
2.	Gregory Campoli	NY Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Gerry Dunbar	NPCC	NPCC	10
6.	Brian Evans-Mongeon	Utility Services	NPCC	7
7.	Dean Ellis	Dynegy Generation	NPCC	5
8.	Brian L. Gooder	Ontario Power Generation	NPCC	5

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

9.	Kathleen Goodman	ISO New England	NPCC	2
10.	Chantel Haswell	FPL Group Inc	NPCC	5
11.	David Kiguel	Hydro One Networks	NPCC	1
12.	Michael R. Lombardi	Northeast Utilities	NPCC	1
13.	Randy MacDonald	New Brunswick System Operator	NPCC	2
14.	Bruce Metruck	NY Power Authority	NPCC	6
15.	Lee Pedowicz	NPCC	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	Saurabh Saksena	National Grid	NPCC	1
19.	Michael Schiavone	National Grid	NPCC	1
20.	Peter Yost	Consolidated Edison of New York	NPCC	3
21.	Mike Garton	Dominion Resources	NPCC	5

2.	Group	Richard Kafka	Pepco Holdings, Inc - Affiliates	1, 3, 5, 6

Additional Member	Additional Organization	Region	Segment Selection
1. Alvin Depew	Potomac Electric Power Company	RFC	1
2. Carl Kinsley	Delmarva Power & Light Company	RFC	1
3. Evan Sage	Potomac Electric Power Company	RFC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
4.	Rob Wharton	Atlantic City Electric	RFC	1									
3.	Group	Kenneth D. Brown	PSEG Companies	1, 3, 5, 6									
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1.	Dave Murray	PSEG Power	RFC	5									
2.	Jim Hebson	PSEG ER &T	NPCC	6									
3.	Scott Slickers	PSEG Connecticut	NPCC	5									
4.	Jerzy Slusarz	Odessa power Partners	ERCOT	5									
5.	Jim Hubertus	PSEG	RFC	1,3									
4.	Group	Denise Koehn	Bonneville Power Administration	1, 3, 5, 6									
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1.	Dean Bender	BPA	WECC	1									
5.	Group	Doug Hohlbaugh	FirstEnergy	1, 3, 4, 5, 6									
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1.	Sam Ciccone	FE	RFC	1, 3, 4, 5, 6									
6.	Group	Ben Li	IRC Standards Review Committee	2									
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1.	Bill Phillips	MISO	MRO	2									
2.	Patrick Brown	PJM	RFC	2									
3.	James Castle	NYISO	NPCC	2									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
4.	Greg Van Pelt	CAISO	WECC 2										
5.	Charles Yeung	SPP	SPP 2										
6.	Steve Myers	ERCOT	ERCOT 2										
7.	Mark Thompson	AESO	WECC 2										
7.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee	10									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	WPS Corp	MRO	3,4,5,6
4.	Jason Marshall	Midwest ISO	MRO	2
5.	Jodi Jenson	Western Area Power Admin.	MRO	1,6
6.	Ken Goldsmith	Alliant Energy	MRO	4
7.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
8.	Eric Ruskamp	Lincoln Electric System	MRO	1,3,5,6
9.	Joseph Knight	Great River Energy	MRO	1,3,5,6
10.	Joe DePoorter	Madison Gas & Electric	MRO	3,4,5,6
11.	Scott Nickels	Rochester Public Utilities	MRO	4
12.	Terry Harbour	Mid American Energy Co.	MRO	1,3,5,6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
8.	Group	Mike Garton	Dominion Electric Market Policy	1, 3, 5, 6									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michael Gildea	Dominion Resource Services	NPCC	5
2.	Louis Slade	Dominion Resource Services	SERC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Individual	Brent Ingebrigtson	E.ON U.S. LLC	X		X		X	X				
10.	Individual	William Gallagher	Transmission Access Policy Study Group	X		X	X	X	X				
11.	Individual	Jana Van Ness, Director Regulatory Compliance	Arizona Public Service Company	X		X		X	X				
12.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
13.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
14.	Individual	Andy Tillery	Southern Company	X		X							
15.	Individual	Bill Middaugh	TSGT System Planning Group	X									
16.	Individual	Gene Henneberg	NV Energy	X		X		X					
17.	Individual	Steve Wadas	NPPD	X									
18.	Individual	Joylyn Faust	Consumers Energy			X	X	X					
19.	Individual	Jonathan Meyer	Idaho Power - System Protection	X		X		X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
20.	Individual	Michael Gammon	Kansas City Power & Light	X		X		X	X				
21.	Individual	Dan Rochester	Independent Electricity System Operator		X								
22.	Individual	Bill Miller	ComEd	X		X		X					
23.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
24.	Individual	Brian Evans-Mongeon	Utility Services								X		
25.	Individual	Tribhuwan Choubey	Southern California Edison	X									
26.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
27.	Individual	Kathleen Goodman	ISO New England Inc.		X								
28.	Individual	Robert Ganley	Long Island Power Authority	X									
29.	Individual	Kirit Shah	Ameren	X		X		X	X				
30.	Individual	Thad Ness	American Electric Power	X		X		X	X				
31.	Individual	Michael Moltane	ITC Holdings	X									
32.	Individual	Not indicated	Not Indicated										
33.	Individual	Laura Zotter, Steve Myers	ERCOT ISO		X								
34.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
35.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
36.	Individual	Greg Rowland	Duke Energy	X		X		X	X				

1. **The Applicability Section (4.1.2 and 4.1.4) and Requirement R5 (previously Requirement R3) have been modified to address the directive in Paragraph 60 of Order no. 733. Do you agree that this is an acceptable and effective method of meeting this directive? If not, please explain.**

Summary Consideration:

Several commenters wanted to know what is meant by "critical to the reliability of the Bulk Electric System (BES)". The SDT notes that although the phrase "critical to reliability of bulk electric system" appears in the approved PRC-023-1 and is used in Order No. 733, the SDT recognizes that use of the same or similar terms in multiple standards will result in confusion. Use of the phrase "critical to reliability of the Bulk Electric System" in PRC-023 is intended to have meaning specific to the issue of relay loadability; specifically to identify facilities, that if they trip due to relay loadability following an initiating event, may contribute to undesirable system performance similar to what occurred during the August 2003 blackout. The SDT has modified the standard to replace the phrase "critical to the reliability of the bulk electric system" with "that must comply with this standard." The SDT believes this will avoid potential confusion and that reliability will be adequately addressed because the criteria in Attachment B identify all facilities that must be subject to this standard to maintain reliability of the Bulk Electric System.

Several commenters indicated that the phrase "low voltage terminals" is open to interpretation. This term is part of the existing standard and not included in the scope of the SAR; however, Attachment B will clarify the criteria to determine which facilities must comply with the standard.

The SDT revised sections 4.1.2 and 4.1.4 for consistency and to refer to facilities "determined by the Planning Coordinator to comply with this standard."

Commenters indicated that they did not believe the standard should apply to facilities below 100 kV; however, in Order 733, NERC was directed to apply PRC-023 to facilities below 100 kV, as well as 100 kV to 200 kV, and to provide criteria to establish which of those facilities to which PRC-023 was to apply. As noted with this posting, the criteria was posted for public comment and is intended to be included with the next posting of this standard.

Commenters indicated that they did not believe the standard should apply to facilities below 100 kV; however, in Order 733, NERC was directed to apply PRC-023 to facilities below 100 kV, as well as 100 kV to 200 kV, and to provide criteria to establish those facilities to which PRC-023 was to apply. As noted with this posting, the criteria were posted for public comment and will be included with the next posting of this standard.

Commenters were reluctant to offer a firm response to the proposed modifications without reviewing the proposed criteria in Attachment B. As noted with this posting, the criteria were posted for public comment and will be included with the next posting of this standard.

The SDT reverted the voltage threshold in section 4.1.2 to the original text because commenters suggested that only facilities below 100 kV that are on the Regional Entity's list should be subjected to the criteria in Attachment B, while all facilities between 100 kV and 200 kV should be subject to the criteria in Attachment B.

The SDT added a new 4.1.3 "Transmission lines operated below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry and are also determined by the Planning Coordinator as required to comply with this standard. "

The SDT renumbered old 4.1.3 to 4.1.4.

The SDT renumbered old 4.1.4 to 4.1.5 and reverted the voltage threshold to the original text consistent with the modification to section 4.1.2.

The SDT added "4.1.6 Transformers with low voltage terminals connected below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry and are also determined by the Planning Coordinator as required to comply with this standard."

In response to comments that Requirement R5 is confusing the SDT deleted “to prevent cascading when protective relay settings limit transmission loadability” from Requirement R5. Removing this term does not change the intent of the requirement.

Commenters indicated that the modifications to the applicability section may have the unintended consequence of increasing the burden on Distribution Providers (DPs) with no reliability benefit; however, 1) the proposed modifications are directed changes and 2) the DPs would only be affected if the Planning Coordinators apply the criteria in Attachment B and determine that the DPs have a facility that must comply with the standard.

One comment indicated that Requirement R1’s VRF “High” has no justification. The SDT thinks that the revision to Requirement R1 to include below 200 kV facilities should have no impact on the VRF assignment. If a facility is designated as a facility critical to the reliability of the BES the impact on reliability is High regardless of the voltage level.

Some commenters noted the Reliability Coordinator (RC) is included in the SAR, but the SDT did not include the RC in the applicability section of the standard. The SDT notes that the SAR contains a list of entities that could potentially be included in the standard, but it is not necessary that the SDT include each entity in the applicability section of the standard.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	The revised Applicability paragraph 4.1.4 reads:4.1.4 Transformers with low voltage terminals connected below 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System (BES). The phrase "low voltage terminals" is open to interpretation because some transformers have low-voltage terminals which are do not supply a load, or supply only local substation AC service. Sometimes the transformer is a 3-winding bank, with the low-voltage winding not used, or the low-voltage winding is used solely to provide additional grounding, as in the case of a delta-connected tertiary, unconnected to any load. Is this what is intended? If yes, then they should remove the ambiguity. Note the phrase "low-voltage" terminal was part of Revision 1 and is unchanged by Revision 2, however, the new applicability to below 200 kV raises the new concern. What is meant by “critical to the reliability of the Bulk Electric System (BES)”? Also, replace “as designated” with “and designated”.Suggest 4.1.4 be revised to read:4.1.4 Transformers with low voltage terminals connected below 200 kV and designated by the Planning Coordinator as Critical Assets. Clarification is needed to explain the disconnect between FERC’s “sub-100kV”, and the proposed “below 200kV”.
IRC Standards Review Committee	No	We believe this directive needs to be addressed by a full standards drafting team to ensure the precise language is crafted to adequately address the directive. Furthermore, we believe only the full standards drafting team could identify equally effective alternatives to the Commission’s directives as they have made

Organization	Yes or No	Question 1 Comment
		clear they allow in this Order and many others. Some immediate concerns with the proposal include: 1) It is not clear what a "critical facilities list identified by the Regional Entity" is as specified within the order so addressing the directive is a challenge. This standard is not the appropriate venue for development or consideration of a critical facilities list. There is a supplemental SAR in process for the Reliability Coordination project that is to address that topic. 2) Our understanding is that the application of NERC standards is limited to the BES. Thus, facilities below 100 kV must be included in the Regional Entity definition of BES to be eligible. The requirements should reflect this. The way the proposed standard reads, one might conclude the PC must test every facility below 100 kV. This surely can't be the intent.3) Furthermore, the directive appears to require some action on the Regional Entities. From paragraph 60, "We also direct that additions to the Regional Entities' critical facility list be tested for their applicability to PRC-023-1 and made subject to the Reliability Standard as appropriate." It is not clear how this directive is reflected in the standard to ensure that this work is completed prior to the PC's performing their assessment for below 200 kV facilities. This standard is not the appropriate venue to determine or revise a critical facilities list, nor is it appropriate for a Regional Entity to establish such a list. The bottom line is that the changes here are significant enough that they would benefit from a group of experts reviewing the directives and proposing the precise language that is needed.
MRO's NERC Standards Review Subcommittee	No	However, this response is conditional depending on whether the criteria that will be established within Attachment B (see R5.1) are reasonable and apply to properly qualified facilities below 200 kV.
Dominion Electric Market Policy	No	It depends on what Attachment B (R5.1) requires once it is developed. Without knowledge of the final content developed for Attachment B, we do not support this.
E.ON U.S. LLC	No	E.ON U.S. believes that it is confusing the way R5 is currently written due to the last part of the sentence " ... when protective relay settings limit transmission loadability." There is a need for clarification on how this is to be applied. As an alternative: If the directive is to have the Planning Coordinator determine which sub-100kV facilities should be subject to the Reliability Standard; R5 should be modified to read "Each Planning Coordinator shall apply the criteria in Attachment B to determine which of the facilities in its Planning Coordinator Area are to be included in 4.1.2 and 4.1.4."
Transmission Access Policy Study Group	No	The modifications to the Applicability Section meet the FERC directive but have the unacceptable unintended consequence of increasing the burden on DPs with no reliability benefit. Specifically, the modifications make all DPs potentially subject to PRC-023, thus requiring all DPs to incur costs to determine whether the standard is applicable to them. Because PRC-023 should never be applicable to a DP in its capacity as a DP (as opposed to a TO that also happens to be registered as a DP), as explained in TAPS' response to question 6 below, the SDT should simply remove DPs from the Applicability section to prevent the significant potential

Organization	Yes or No	Question 1 Comment
		for confusion and unnecessary costs.
Arizona Public Service Company	No	Agree with the content. However, there is no justification for VRF to be High for the circuits lower than 200 kV.
Kansas City Power & Light	No	Agree the changes for 4.1.2 and 4.1.4 are effective in meeting the “add in” approach in the FERC order. However, do not agree with the approach in R5. R5 proposes to establish the criteria by which Reliability Coordinators will determine facilities critical to the reliability of the BES. There are a variety of differing, and often complex, operating conditions that dictate the need for transmission facilities. The TPL standards require extensive studies of the transmission system be performed under steady state and dynamic conditions to understand and identify sensitive areas of the transmission system and enable Reliability Coordinators to identify flowgates in their respective regions. In light of the Reliability Coordinators awareness of transmission sensitivities through these studies, it seems unnecessary to dictate to the Reliability Coordinators additional criteria.
Utility Services	No	The modifications to the Applicability Section meet the FERC directive but have the unacceptable unintended consequence of increasing the burden on DPs with no reliability benefit. Specifically, the modifications make all DPs potentially subject to PRC-023, thus requiring all DPs to incur costs to determine whether the standard is applicable to them. Because PRC-023 should never be applicable to a DP in its capacity as a DP (as opposed to a TO that also happens to be registered as a DP), as explained in our response to question 6 below, the SDT should simply remove DPs from the Applicability section to prevent the significant potential for confusion and unnecessary costs.
ISO New England Inc.	No	We believe this directive needs to be addressed by a full standards drafting team to ensure the precise language is crafted to adequately address the directive. Furthermore, we believe only the full standards drafting team could identify equally effective alternatives to the Commission’s directives as they have made clear they allow in this Order and many others. Some immediate concerns with the proposal include: 1) Our understanding is that the application of NERC standards is limited to the BES. Thus, facilities below 100 kV must be included in the Regional Entity definition of BES to be eligible. The requirements should reflect this. The way the proposed standard reads, one might conclude the PC must test every facility below 100 kV. This surely can’t be the intent.2) Furthermore, the directive appears to require some action on the Regional Entities. From paragraph 60, “We also direct that additions to the Regional Entities’ critical facility list be tested for their applicability to PRC-023-1 and made subject to the Reliability Standard as appropriate.” It is not clear how this directive is reflected in the standard to ensure that this work is completed prior to the PC’s performing their assessment for below 200 kV facilities. The bottom line is that the changes here are significant enough that they would benefit from a group of experts reviewing the directives and proposing the precise language that is needed.

Organization	Yes or No	Question 1 Comment
Long Island Power Authority	No	There appears to be a disconnect between FERC's "sub 100 kV" and proposed "below 200 kV" revision in the Applicability Section. LIPA seeks clarification on this. Also, by whom and by which method will the criticality of the substations be ascertained?
Ameren	No	Attachment B as mentioned in R5 is not available for review.
American Electric Power	No	AEP understands the intent of the FERC Order (Paragraph 60) to address the sub-100 KV facilities only if they are associated with critical facilities above 100 KV. The applicability and the associated requirements should be reworded to ensure that the Planning Coordinator does not have to identify critical facilities below 100 KV.
Southern California Edison	No	Applicability clause 4.12 and 4.14 - Formulating a consistent methodology test to determine for a sub 200KV facility by the Planning Coordinator is quite an uphill task keeping in view the different circuit configuration different utilities may have. It is best left alone to each utility to determine the facilities which can be a candidate for inclusion as a bulk power system. The current risk based assessment criteria to determine bulk power facility should be continued.
American Transmission Company	Yes	However, this affirmative response is conditional depending on whether the criteria that will be established within Attachment B (see R5.1) are reasonable and apply to properly qualified facilities below 200 kV.
Pepco Holdings, Inc - Affiliates	Yes	While philosophically we do not agree that this standard should apply to facilities below 100kV (i.e. facilities that are not defined as BES facilities) we believe that as long as a sound engineering methodology is developed and applied uniformly to identify those facilities critical to the reliability of the BES, then the revised wording is acceptable. Our response, however, is qualified based on being granted an opportunity to comment and vote on the methodology once it is developed.
NPPD	Yes	As long as you keep BES.
Independent Electricity System Operator	Yes	We agree with the Applicability Section and the modification to R5. Note that there is a discrepancy between the entities listed in the Applicability Section and those checked off in the SAR. The latter indicates that the SAR is also applicable to the RC, which we do not believe is required.
Bonneville Power Administration	Yes	
FirstEnergy	Yes	

Organization	Yes or No	Question 1 Comment
PacifiCorp	Yes	
Southern Company	Yes	
TSGT System Planning Group	Yes	
NV Energy	Yes	
Consumers Energy	Yes	
Idaho Power - System Protection	Yes	
ComEd	Yes	
Manitoba Hydro	Yes	
ITC Holdings	Yes	
	Yes	
Xcel Energy	Yes	
Duke Energy	Yes	
Wisconsin Electric		No comment

2. R1 has been modified to address the directive in Paragraph 244 of Order no. 733. Do you agree that this is an acceptable and effective method of meeting this directive? If not, please explain.

Summary Consideration:

Commenters indicated for a variety of reasons that the requirement related to out-of-step blocking added to Requirement R1 is confusing. The SDT agrees and removed out-of-step blocking from Requirement R1. The requirement pertaining to evaluation of out-of-step blocking protection has been moved to a separate requirement (now Requirement R2) to more clearly delineate this requirement from assessment of relay loadability of phase protective relays.

One commenter noted that it is not clear how loadability requirements apply during fault conditions. In the new requirement the SDT clarified that the evaluation must ensure that out-of-step blocking elements allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.

Some commenters indicated that the word “settings” should be replaced throughout R1 when referring to a part, or sub-requirement of R1. The SDT modified Requirement R1 by replacing the word “settings” with “criteria.” This is consistent with the main Requirement R1 which in the presently approved standard (PRC-023-1) refers to sub-requirements R1.1 through R1.13 as criteria to prevent phase protective relay settings from limiting transmission system loadability.

Some commenters identified an error in the draft standard in criterion 9 in Requirement R1 that resulted in omitting a phrase contained in the presently approved standard. The SDT modified criterion 9 in Requirement R1 to reinsert the deleted phrase.

One commenter noted that this directive needs to be addressed by a full standard drafting team to adequately address this directive and identify equally effective alternatives to the Commission’s directives. The Relay Loadability Standard Drafting Team that developed PRC-023-1 has been reconvened to address the directed modifications to the standard. The SDT believes that the issues indentified in Order No. 733 can be addressed adequately by this SDT with industry stakeholder input through the NERC Standard Development Process.

One commenter indicated that they agreed with the inclusion of Section 2 of Attachment A in the Requirement Section but the proposed modification may not fully meet the directive that the additional requirement is assigned a VRF and VSL. This may require the creation of a separate main requirement rather than simply including the condition as a part of a requirement. However, the VRFs and VSLs are associated directly with R1, and thus all its’ subparts/criteria. Therefore, as Attachment A is referenced as being part of R1, the R1 VRFs and VSLs automatically apply.

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	1. The last sentence in R1 should be revised to read: 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. 2. Settings are to be applied as listed following:”Setting” should be replaced throughout R1 when referring to

Organization	Yes or No	Question 2 Comment
		a part, or sub-requirement of R1. The terminology should be whatever is preferred by NERC.Requirement R1, Parts 7, 8 and 9: 3. Requirement R1, Parts 7, 8 and 9, replace the phrase “under any system configuration” with "under any system condition:" 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 condition.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 condition.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 [___] to the under any system condition. [Brackets added, also see further comment on missing wording following]This phrase "under any system configuration" could be construed as being too all-inclusive, as one could postulate multiple events, e.g., simultaneous outages, which however unlikely could permit power flows in a direction for which the system was not originally designed. As with the second comment below, the phrase "under any system condition" was part of Revision 1 and is unchanged by Revision 2, however, the new applicability to below 200 kV creates the new concern. 4. Requirement 1, part 9:As currently written, Requirement 1, part 9 states: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 [___] to the under any system configuration. [Brackets added]Some words are missing. The brackets have been added above to show one place where at least some of the needed wording may be missing. A rewrite is necessary in order for this sentence to make any sense.
Pepco Holdings, Inc - Affiliates	No	The revised wording in paragraph R1 regarding out-of-step blocking schemes is confusing. We suggest rewording the paragraph by splitting the sentence as follows: ...while maintaining reliable protection of the BES for all fault conditions. Use of out-of-step blocking schemes shall be evaluated to ensure that they do not block tripping for faults during the loading conditions defined within these requirements.
Bonneville Power Administration	No	The modified Requirement R1 requires that one of the 13 criteria be used to prevent out-of-step blocking schemes from blocking tripping for fault conditions. The problem is that the 13 criteria are only related to loading conditions, and it is not clear how they would be applied to prevent out-of-step blocking schemes from blocking a trip during a fault, or if it is even possible to use these criteria for this purpose. The modified Requirement R1 requires actions that are ambiguous and we cannot support it as written.
IRC Standards Review	No	We believe this directive needs to be addressed by a standards drafting team to ensure the precise language is crafted to adequately address the directive. Furthermore, we believe only the full standards drafting team

Organization	Yes or No	Question 2 Comment
Committee		could identify equally effective alternatives to the Commission's directives as they have made clear they allow in this Order and many others.
E.ON U.S. LLC	No	Since correct operation of the out-of-step blocking feature is integral to and only a single component of a successful trip operation (for fault conditions), this is already included in the requirement to "maintain reliable protection of the BES for all fault conditions" and does not have to be mentioned separately. Also, R1 (as written) may be interpreted to require one of the settings (1 through 13) to be used to prevent out-of-step blocking schemes from blocking tripping for fault conditions. But Settings 1 thru 13 do not address specific setting criteria for out-of-step blocking.
TSGT System Planning Group	No	We suggest that the added phrase be removed from R1 and a new requirement created. Suggested wording is "Protection Systems that block for stable swings or out-of-step conditions shall be evaluated to ensure that appropriate tripping will occur for in-section faults that occur during the condition. Some additional delay may be required and is acceptable to ensure that the appropriate tripping occurs."
NV Energy	No	The proposed phrase added to R1 is only a start: ". . . , and to prevent its out-of-step blocking schemes from blocking tripping for fault conditions." The specific wording proposed by the Drafting Team may prevent using the out-of-step-block functions of many modern and widely used line protection relays (e.g. SEL-321 and later models and GE-UR). These relay's OSB function first blocks the protection elements from tripping, then uses a short delay and/or other information to determine whether the observed and perhaps evolving condition really represents a fault, in which case the blocking is reset to allow tripping. Such a block/reset operation is the most common technology available and would appear to lie within the intent of FERC in paragraph 244, but could be excluded by the presently proposed language. If an out-of-step blocking phrase is inserted in Requirement R1 of the standard, the emphasis should be modified to read something like: ". . . , and its out-of-step blocking schemes must allow tripping for fault conditions." This standard should also require that out-of-step blocking settings coordinate with both the loadability and protection characteristics. The out-of-step blocking references would seem to fit best within the organization of the standard if included as a new Requirement R2 (FERC's paragraph 244 anticipates ". . . an additional Requirement . . ."), with re-numbering of the proposed R2 through R5 as R3 through R6. The essential content of the DT's proposed phrase in R1 would be included as part of this new R2, which would read something like:R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall evaluate its out-of-step blocking schemes to ensure that both: R2.1. Out-of-step blocking schemes allow tripping for fault conditions during the loading conditions determined from Requirement R1 parts R1.1 through R1.13. R2.2. Relay out-of-step blocking settings coordinate with both the relay loadability characteristic determined from Requirement R1 parts R1.1 through R1.13 and the facility protection settings. The Measure for this proposed R2 would read something like:M2.The Transmission Owner, Generator Owner, and Distribution Provider with out-of-step blocking schemes shall have evidence such as spreadsheets or

Organization	Yes or No	Question 2 Comment
		summaries of calculations to show that each of its out-of-step blocking schemes is set to comply with the requirements of R2.1 and R2.2. The VSL for R1 would not change; specifically it would not reference out-of-step blocking schemes. The VSL for this proposed new R2 would be “Severe” and read something like:A Transmission Owner, Generator Owner, or Distribution Provider did not allow its out-of-step blocking schemes to trip for fault conditions during the loading conditions determined from Requirement R1 parts R1.1 through R1.13. ORA Transmission Owner, Generator Owner, or Distribution Provider did not coordinate operation of its out-of-step blocking schemes with both the relay loadability characteristic determined from Requirement R1 parts R1.1 through R1.13 and the facility protection settings.
Independent Electricity System Operator	No	We agree with the inclusion of Section 2 of Attachment A in the Requirement Section but the proposed modification may not fully meet the directive that the additional requirement is assigned a VRF and VSL. This may require the creation of a separate main requirement rather than simply including the condition as a part of a requirement.
Southern California Edison	No	Requirement R1.7, R1.8, R1.13 do not provide a clear guideline on generators connected to the load center on Radial basis, where load current into the generators (forward direction current seen by the relay) is just an auxiliary load and insignificant compared to the transmission line rating.
ISO New England Inc.	No	Requirement R1, Parts 7, 8 and 9:Requirement R1, Parts 7, 8 and 9, replace the phrase “under any system configuration” with "under any system condition:" 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 systemcondition.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 systemcondition.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 [___] to the under any system condition. [Brackets added, also see further comment on missing wording following]This phrase "under any system configuration" could be construed as being too all-inclusive, as one could postulate multiple events, e.g., simultaneous outages, which however unlikely could permit power flows in a direction for which the system was not originally designed. As with the second comment below, the phrase "under any system condition" was part of Revision 1 and is unchanged by Revision 2, however, the new applicability to below 200 kV creates the new concern.Requirement 1, part 9:As currently written, Requirement 1, part 9 states: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 [___] to the under any system configuration. [Brackets added] Some words are missing. The brackets have been added above to show one place where at least some of the needed wording may be missing. A rewrite is

Organization	Yes or No	Question 2 Comment
		necessary in order for this sentence to make any sense.
Long Island Power Authority	No	Requirement R1, Parts 7, 8 and 9, replace the phrase “under any system configuration” with "under any system condition:" This phrase "under any system configuration" could be construed as being too all-inclusive, as one could postulate multiple events, e.g., simultaneous outages, which however unlikely could permit power flows in a direction for which the system was not originally designed. Requirement 1, part 9:As currently written, Requirement 1, part 9 states: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 [___] to the under any system configuration. [Brackets added] Some words are missing. The brackets have been added above to show one place where at least some of the needed wording may be missing. A rewrite is necessary in order for this sentence to make any sense.
ITC Holdings	No	The proposed wording seems out of place in this requirement and is not clear as how it is being applied to subrequirements 1 - 13
NPPD	Yes	I'm ok with that. It could have easily been left in Attachment A. You didn't bring the other language from attachment A to R1. You could of created a separate requirement for OOS, but I'm fine with moving it to R1.
FirstEnergy	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
Dominion Electric Market Policy	Yes	
Arizona Public Service Company	Yes	
American Transmission Company	Yes	
Southern Company	Yes	
Consumers Energy	Yes	
Idaho Power - System Protection	Yes	

Organization	Yes or No	Question 2 Comment
Kansas City Power & Light	Yes	
ComEd	Yes	
Manitoba Hydro	Yes	
Ameren	Yes	
American Electric Power	Yes	
	Yes	
Xcel Energy	Yes	
Duke Energy	Yes	
Wisconsin Electric		No comment

3. Requirement R1, setting 10 has been modified to address the directive in Paragraph 203 of Order no. 733. Do you agree that this is an acceptable and effective method of meeting this directive? If not, please explain.

Summary Consideration:

Many commenters were concerned about the coordination with the relay loadability requirements of R1 – criterion 1.10 with the transformer damage curve as expressed in IEEE C37.91 Figure A4, which defines transformer through-fault withstand capability as starting at twice the nominal nameplate rating; R1, criterion 1.10 requires that loadability be 150% of the maximum nameplate (which itself is often 1.66 times the nominal nameplate – resulting in loadability of over 2.5 times the nominal nameplate rating).

IEEE C37.91 Figure A5 has two components to the thermal damage curve for through-faults: the "thermal component" begins at 2x the transformer nominal nameplate rating, and seems to be the root of commenters' concerns. The "mechanical component" begins at a current equal to the reciprocal of the twice the transformer impedance. The commenters are correct in their characterization of the "thermal component" of the transformer damage curve, in that it is not possible to satisfy the posted PRC-023-2 R1, criterion 10 and also protect the transformer for currents in this region. Upon careful consideration of FERC Order 733, the SDT revised R1 criterion 10 to reference only the mechanical withstand capability.

Many commenters questioned the inclusion of "limiting piece of equipment" rather than "transformer", as the fault withstand capability of terminal equipment (switches, breakers, current transformers, etc) may be unavailable. Upon further consideration of FERC Order 733, the SDT modified criterion 10 by replacing "limiting equipment" with "transformer."

Organization	Yes or No	Question 3 Comment
Pepco Holdings, Inc - Affiliates	No	It would appear that this requirement has already been addressed in the R1 introductory paragraph by the phrase "...while maintaining reliable protection of the BES for all fault conditions." How could one "maintain reliable protection of the BES" if relays are set with operating times that result in equipment being exposed to fault levels and durations that exceed their capability. This introductory requirement to provide reliable fault protection applies to all sub requirements not just to section 10 (old R1.10). As such, the added language in section 10 seems redundant and superfluous. Secondly, if the proposed language were to remain in section 10, why is the term "limiting piece of equipment" used and not just "transformer"? It appears the major concerns related to the comments contained in Order 733 were around exceeding transformer fault level/duration limitations. If that is the concern, why not just use the phrase "do not expose the transformer to fault levels and durations that exceeds its capability"
Bonneville Power Administration	No	In some cases, Section 10 of Requirement R1 would be impossible to meet. For example, a 150/200/250 MVA, OA/FOA1/FOA2 transformer is required by Section 10 to have its protection set so that it doesn't operate at or below 150% of the maximum transformer rating of 250MVA, or 1.5x250=375MVA. The modified Section 10 would also require that the protection not expose the transformer to a fault level and duration that

Organization	Yes or No	Question 3 Comment
		exceeds its capability. According to IEEE C37.91, a through-fault of two times the transformers base rating, 2x150=300MVA, will be damaging to the transformer. For this particular transformer, which is not unusual, Requirement R1, Section 10, requires the protection to operate for through faults of 300MVA or greater, but not operate for loads of 375MVA or less. It is impossible to simultaneously meet both of these conditions, so Section 10 is unacceptable. One possible way to correct the problem is to change the requirement so that the protection does not operate below 200% of the transformer base rating. This would allow the protection to meet IEEE C37.91 for through-faults and still allow overloading of the transformer.
FirstEnergy	No	Although it is true that the FERC directive specifically states "limiting piece of equipment" their reasons and justifications all involve transformers. We propose replacing "limiting piece of equipment" with "transformer" would meet the FERC's reliability concern as well as provide clarity to applicable entities. We believe this is an equally effective means of meeting the directive.
IRC Standards Review Committee	No	We believe this directive needs to be addressed by a full standards drafting team to ensure the precise language is crafted to adequately address the directive. Furthermore, we believe only the full standards drafting team could identify equally effective alternatives to the Commission's directives as they have made clear they allow in this Order and many others. Additionally, we question if this directive should be addressed in the FAC standards rather than in PRC-023.
MRO's NERC Standards Review Subcommittee	No	The word change meets the strict interpretation of the directive, but it is not necessarily improving the reliability of the system. Faults are cleared in cycles and transformer damage curves do not start until at least one second
Dominion Electric Market Policy	No	The requirement is not clear. For example, how do we determine and verify the limiting piece of equipment under fault conditions? It might be a splice or a jumper. Since the document refers to duration, this seems to apply mainly to transformer overcurrent relaying which would be for overload protection not fault protection that has no intentional delay.
E.ON U.S. LLC	No	E.ON U.S. is concerned that the proposal requires a fault protection scheme separate from the phase overload relays. With the phase overload relays set at 150% of the maximum transformer nameplate, they (by themselves) will not be able to coordinate with the transformer damage curve (as defined by IEEE) for low level faults.R1, Section 10 meets the directive of Paragraph 203; however it is not clear that Section 10 only applies when there is no high side breaker at the transformer, as discussed in Order No. 733. E.ON U.S. recommends that an exclusion of the transmission line relay settings should be considered when transformer overload protection is provided by other means (i.e. A low side breaker trip or a direct transfer trip of the remote breaker initiated by an overload relay installed on the transformer).

Organization	Yes or No	Question 3 Comment
NPPD	No	Setting the relay to 150% of a 336MVA or 500MVA transformer can force you to cross the transformer damage curve and now your transformer is at risk to loss of life.
Idaho Power - System Protection	No	The reworded Requirement should to be clarified. The fault level and duration that the limiting element will be exposed can be a function of fault location and contingencies, such as relay failures, that are not addressed or defined. No measure is specified in the reliability standard that will demonstrate compliance with the revised requirements in R1.10.
Kansas City Power & Light	No	Although setting #10 includes language to protect the most limiting element for a transmission circuit ending with a transformer, the relay settings in the bulleted items are absent any consideration for other elements such as disconnect switches, wave traps, current transformers, potential transformers, etc. and are only with concern to the transformer. The relay settings should consider the fault current capabilities of all the facilities involved and be set in magnitude and duration of the lowest facility rating.
Ameren	No	The language is not clear. It appears that the transmission line relays are being used as the thermal overload protection for the transformer.
ITC Holdings	No	R1 -10 is all about loadability of the relays protecting the transformer. If the requirements of R1-10 cannot be met without exceeding the transformer damage curve, then we go to R1-11. We do not feel that there should be anything to do with fault duty.
Duke Energy	No	R1.10 has added the requirement that protection settings can't expose transformers to fault levels and durations that exceeds its capability, while at the same time not operate at or below 115% of highest emergency rating. We would argue that an overcurrent relay cannot be set to satisfy both requirements. A transformer's through-fault protection curve (C37.91) begins at 200% of the transformers self-cooled rating. The highest emergency rating is commonly 150% (or higher) of the transformer's highest (cooled) rating. Overcurrent relays could not be set to coordinate with both the damage curve and the overload rating.
South Carolina Electric and Gas	No	This requirement needs to be refined to clearly state the intent. It is unclear if "limiting piece of equipment" is referring to just transformers or other elements. Some of the elements involved in the construction of a transmission line/transformer arrangement such as line conductors, etc. may not have published fault current ratings. It is unclear how to determine the most limiting piece of equipment if published fault current ratings are not available for these devices
American Transmission	Yes	The word change meets the strict interpretation of the directive, but it is not necessarily improving the reliability of the system. Faults are cleared in cycles and transformer damage curves do not start until at least

Organization	Yes or No	Question 3 Comment
Company		one second.
Arizona Public Service Company	Yes	
Northeast Power Coordinating Council	Yes	
PacifiCorp	Yes	
Southern Company	Yes	
TSGT System Planning Group	Yes	
NV Energy	Yes	
Consumers Energy	Yes	
ComEd	Yes	
Manitoba Hydro	Yes	
ISO New England Inc.	Yes	
Long Island Power Authority	Yes	
American Electric Power	Yes	
	Yes	
Xcel Energy	Yes	
Wisconsin Electric		No comment

4. **Requirement R3 has been added to address the directive in Paragraph 186 of Order no. 733. Do you agree that this is an acceptable and effective method of meeting this directive? If not, please explain.**

Summary Consideration:

The SDT modified the wording of R4 as follows. "Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to utilize Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability shall provide...." as a result of comments.

The SDT agreed to remove the Regional Entity from the list of entities receiving this information in Requirement R4.

Comments indicated that all relay setting limitations should be included in the Facility Rating per FAC-008. The operator will then be made aware of any and all relay limitations through the use of those ratings (FAC-009). FERC Order 733 paragraph 186 requires an additional notification of relay setting limitations specifically for relay settings that are set based upon the 15 minute criteria. This is being done to ensure that transmission operators have knowledge of which facilities have relays set using a 15 minute criteria and which facilities have relays set using a 4-hour criteria. The SDT believes that requiring periodic submittals of this information will help create a clear and less ambiguous requirement and improve measurability which should aid applicable entities in compliance and result in more uniform enforcement actions.

Organization	Yes or No	Question 4 Comment
Bonneville Power Administration		This change adds an additional burden to the applicable entities, but serves no purpose other than to satisfy FERC's misinterpretation of what a fifteen-minute facility rating is.
ERCOT ISO		The entities who receive the list of facilities should be the same from R3 to R4.
Northeast Power Coordinating Council	No	Referring to the response to Question 2 above, "Setting" should be replaced with Part, or Sub-requirement, whichever is the terminology preferred by NERC to use.
Pepco Holdings, Inc - Affiliates	No	To avoid confusion, the wording of R3 should be revised as follows: "Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to utilize Requirement R1 Setting 2 as the basis for verifying transmission line relay loadability shall provide...." The problem with the SDT's proposed wording of R3 is that suppose a TO chose to utilize R1 Setting 1 criteria (> 150% of 4 hr rating) as their basis for verifying loadability, but the actual relay setting also satisfied criteria R1 Setting 2 (> 115% of 15 min rating) the entity may interpret that they are still obligated to forward the list since the relay settings also satisfied R1 Setting 2 criteria
FirstEnergy	No	We suggest removing the Regional Entity from the list of entities receiving this information since they do not have a reliability-related need for it.

Organization	Yes or No	Question 4 Comment
IRC Standards Review Committee	No	We do not understand the need for this directive or requirement. A relay that is set to operate at 115% greater than the 15-minute rating of the facility does not equate to damage occurring on that facility if operated at that point in 15 minutes. Furthermore, it does not mean the relay will operate in 15 minutes nor does it mean the operator has only 15 minutes to take action. In fact, the operator may have less time depending on the time delay set on the relay. It is no different than any other relay. Usually, the facility will be operated with some buffer so that there is no chance that an entity could trip the facility due to loading above the relay limit. In fact, the transmission operator should be aware of any relay that might be the limiting facility so they can operate the facility with some margin of error to ensure they don't inadvertently cause a relay operation due to loading.
TSGT System Planning Group	No	We think that the data needs to be given only to the Transmission Operators, which is what FERC Order No. 733 requires. We also believe that an initial submittal is sufficient until any responsible entity begins or stops using Requirement 1, Setting 2 for setting a phase protective relay that is used to protect an applicable facility. There is no need for periodic duplicate submittals.
Kansas City Power & Light	No	Do not agree that the Regional Entity be included as a recipient of the list of transmission facilities. By NERC definition, the Regional Entity is the Compliance Monitor and Enforcement Authority for the NERC Reliability Standards and is not an operating entity. It is inappropriate to include Regional Entities as an entity to provide this information outside of the audit process established by the NERC Rules of Procedure. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to obtain this information. See definition below:Regional Entity - The term 'regional entity' is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE's. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.
Independent Electricity System Operator	No	The proposed revision goes beyond what's asked for in the directive as it requires the responsible entities to provide the list to entities other than the TOP. The directive asks for providing the list to the TOP only.
Southern California Edison	No	The relay if set according to Requirement R1.2 are based upon 15 minute highest seasonal facility loading duration. This gives sufficient time for the operators to take manual corrective action, if the deem so. There is no need for the Registered entity to provide a list, as it would not be efficient and cost effective.

Organization	Yes or No	Question 4 Comment
ISO New England Inc.	No	We do not understand the need for this directive or requirement. A relay that is set to operate at 115% greater than the 15-minute rating of the facility does not equate to damage occurring on that facility if operated at that point in 15 minutes. Furthermore, it does not mean the relay will operate in 15 minutes nor does it mean the operator has only 15 minutes to take action. In fact, the operator may have less time depending on the time delay set on the relay. It is no different than any other relay. Usually, the facility will be operated with some buffer so that there is no chance that an entity could trip the facility due to loading above the relay limit. In fact, the transmission operator should be aware of any relay that might be the limiting facility so they can operate the facility with some margin of error to ensure they don't inadvertently cause a relay operation due to loading.
MRO's NERC Standards Review Subcommittee	Yes	
Dominion Electric Market Policy	Yes	
E.ON U.S. LLC	Yes	
Arizona Public Service Company	Yes	
American Transmission Company	Yes	
PacifiCorp	Yes	
Southern Company	Yes	
NV Energy	Yes	
NPPD	Yes	
Consumers Energy	Yes	
Idaho Power - System Protection	Yes	

Organization	Yes or No	Question 4 Comment
ComEd	Yes	
Manitoba Hydro	Yes	
Long Island Power Authority	Yes	
Ameren	Yes	
American Electric Power	Yes	
ITC Holdings	Yes	
	Yes	
Xcel Energy	Yes	
Duke Energy	Yes	
Wisconsin Electric		No comment

5. **Requirement R4 has been added to address the directive in Paragraph 224 of Order no. 733. Do you agree that this is an acceptable and effective method of meeting this directive? If not, please explain.**

Summary Consideration:

The FERC Order "direct(s) the ERO to document, subject to audit by the Commission, and to make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant sub-requirement R1.12."

Since the data is subject to audit, the SDT interprets this to mean that the ERO must gather and have continuously available a list of facilities using Requirement R1 criterion 12. The SDT therefore interprets the "by request" nature of the directive to indicate the way the ERO makes the list available to users, owners and operators of the Bulk-Power System, not how the ERO gathers the data from TOs, GOs and DOs.

As suggested by one of the comments, the SDT intended for registered entities to provide this data to their Regional Entities who would in turn provide it to the ERO. Although some comments have suggested other ways to accomplish this, the majority of responders appear to agree with the SDT proposed method.

Organization	Yes or No	Question 5 Comment
ERCOT ISO		The entities who receive the list of facilities should be the same from R3 to R4.
Northeast Power Coordinating Council	No	R4 addresses the directive, but as commented on previously, "Setting" should be replaced with Part, or Sub-requirement, whichever is the terminology preferred by NERC to use.
IRC Standards Review Committee	No	The objective of R4 as written is unclear and does not conform with the results-based concept in that it does not clearly specify a reliability directive. We suggest removing this requirement altogether as we do not believe this should be an on-going enforceable requirement. Rather, we think it makes more sense for NERC to use section 1600 of its Rules of Procedure to request the data. We believe that NERC and the Commission will likely determine that they don't need to continually receive this data after reviewing it the first time. Nothing in the directive indicates this must be accomplished through a standard. If NERC and FERC do identify a continuing need for the data, the standard could be modified at a later date.
MRO's NERC Standards Review Subcommittee	No	While achievable, this will not come without effort and does not necessarily improve the reliability of the BES commensurate with the compliance burden.

Organization	Yes or No	Question 5 Comment
Arizona Public Service Company	No	FERC Order required the list to be made available for review to users, owners and operators of the Bulk-Power System upon request. Requirement 4 does not include the "request" requirement, implying that the Registered Entity must provide the list without a request. Further, the requirement does not specify what the Regional Entity will do with the list once it is provided.
TSGT System Planning Group	No	FERC Order No. 733 requires the settings be provided upon request and no initial or periodic submittal is required.
Kansas City Power & Light	No	The proposed R4 exceeds the concerns of FERC in this matter. FERC directed a requirement to provide information upon request. The proposed R4 requires data submission without request of the parties with interest to the information. Recommend the SDT consider modifying this requirement to provide this information upon the request of appropriate operating parties.Do not agree that the Regional Entity be included as a recipient of the list of transmission facilities. By NERC definition, the Regional Entity is the Compliance Monitor and Enforcement Authority for the NERC Reliability Standards and is not an operating entity. It is inappropriate to include Regional Entities as an entity to provide this information outside of the audit process established by the NERC Rules of Procedure. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to obtain this information. See definition below:Regional Entity - The term ‘regional entity’ is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE’s. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.
Independent Electricity System Operator	No	The objective of R4 as written is unclear. We speculate that by requiring the TOs, GOs and DPs to provide the list (associated with R1, Section 12) to the REs, the ERO will collect the relevant information from all REs to facilitate provision of such information to owners, users and operators of the BES upon request. If this is the intent, we suggest to replace “REs” with “ERO” to make it a more direct and efficient way to provide the information needed to support the request for information process.The requirement as written does not conform with the results-based concept in that it does not clearly specify a reliability directive. Hence alternatively, we suggest removal of this requirement altogether since the directive asks the ERO to document, subject to audit by the Commission, and to make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities. This can be dealt with outside of the standard process, for example, through RoP 1600.

Organization	Yes or No	Question 5 Comment
Long Island Power Authority	No	FERC order 733 p224 requires that the list of facilities that have protective relays set pursuant to R1.12 of anticipated overload be made available to users, owners, and operators of the BPS. However, the proposed revision to R4 requires the list to be made available to Regional Entity only. Please clarify. Also, FERC order uses the term “by request” which is missing from the proposed revision.
American Transmission Company	Yes	While achievable, this will not come without effort and does not necessarily improve the reliability of the BES commensurate with the compliance burden.
Pepco Holdings, Inc - Affiliates	Yes	
FirstEnergy	Yes	
Dominion Electric Market Policy	Yes	
E.ON U.S. LLC	Yes	
PacifiCorp	Yes	
Southern Company	Yes	
NV Energy	Yes	
NPPD	Yes	
Consumers Energy	Yes	
Idaho Power - System Protection	Yes	
ComEd	Yes	
Manitoba Hydro	Yes	
ISO New England Inc.	Yes	

Organization	Yes or No	Question 5 Comment
American Electric Power	Yes	
ITC Holdings	Yes	
	Yes	
Xcel Energy	Yes	
Duke Energy	Yes	Paragraph 224 addresses R1.12, requiring documentation and making available a list of facilities that have protective relays set pursuant to R1.12. Although Order 733 was silent on R1.13, should the new R4 not also apply to R1.13?
Wisconsin Electric		No comment

6. **Requirement R5 and part 5.1 (previously Requirement R3 and part 3.1) have been modified to establish the framework to address the directive in Paragraph 69 of Order no. 733, although the criteria itself (which will be Attachment B) is still being developed. Do you agree that this is an acceptable and effective method of meeting this directive considering that Requirement R5 is establishing the construct to insert the criteria at a future time in the form of Attachment B? If not, please explain.**

Summary Consideration:

A majority of commenters do not believe, or were unable to determine whether, the construct established in Requirement R5 is an acceptable and effective method of meeting this directive. Almost all commenters, regardless of whether they responded "Yes" or "No," indicated their responses are conditional pending review of the criteria. The criteria that Planning Coordinators will use to determine which facilities must comply with PRC-023 were posted on September 23 for a 20-day informal comment period. The SDT has reviewed Requirement R5 and the criteria in Attachment B and has made conforming changes to ensure no conflicts exist. The full standard with Attachment B will be posted for a 45-day formal comment period.

One commenter disagreed with the approach in Requirement R5, part R5.1, noting there are a variety of differing, and often complex, operating conditions that dictate the need for transmission facilities. The commenter observed it is not necessary to dictate additional criteria because the TPL standards already require extensive studies of the transmission system. The SDT believes the proposed criteria defining the test Planning Coordinators will use to determine which facilities must comply with PRC-023 will address the commenters concerns. The proposed criteria are consistent with the simulations and assessments required by the TPL Reliability Standards and allow the Planning Coordinators to utilize those assessments as directed in Order No. 733.

One commenter noted that the SDT needs to work closely with the Reliability Coordination SDT (Project 2006-06) which is tasked with defining critical facilities or indentifying criteria for developing a list of critical facilities. The commenter disagreed with use of the phrase "facilities that are critical" in this requirement and cautioned that a requirement to create a list of critical facilities should not be addressed in this standard. The SDT notes that although the phrase "critical to reliability of bulk electric system" appears in the approved PRC-023-1 and is used in Order No. 733, the SDT recognizes that use of the same or similar terms in multiple standards will result in confusion. Use of the phrase "critical to reliability of the Bulk Electric System" in PRC-023 is intended to have meaning specific to the issue of relay loadability; specifically to identify facilities, that if they trip due to relay loadability following an initiating event, may contribute to undesirable system performance similar to what occurred during the August 2003 blackout. The SDT has modified the standard to replace the phrase "critical to the reliability of the bulk electric system" with "that must comply with this standard." The SDT believes this will avoid potential confusion and that reliability will be adequately addressed because the criteria in Attachment B identify all facilities that must be subject to this standard to maintain reliability of the Bulk Electric System.

Some commenters noted that Requirement R5, Part 5.3 should require that the Planning Coordinator provide its list of facilities to all Transmission Owners, Generator Owners, and Distribution Providers within its area; not only the entities with facilities on the list. The SDT believes this is consistent with the intent of the requirement and has modified the standard accordingly to make this requirement explicit.

One commenter noted that Requirement R5, Part 5.1 is unnecessary since the process to use the criteria in Attachment B would almost certainly be to simply apply the criteria and that requiring documentation of such a process will result in increased paperwork and additional preparation for an audit without a reliability benefit. The SDT agrees that this part of Requirement R5 is unnecessary and has removed it from the Standard.

Several commenters requested modifications that are outside the scope of the SAR for this project.

- Two commenters indicated Requirement R5 should include wording that limits the scope of the transmission facilities to be evaluated to only those that can be tripped by the relay settings subject to Requirement R1 and that the SDT should add a requirement that the Transmission Owners, Generator Owners, and Distribution Providers provide the Planning Coordinators with a list of such transmission facilities. The SDT believes that since the existing Requirement R3 does not restrict the facilities which the Planning Coordinator must consider, the proposed modifications are outside the scope of the SAR for this project. The SDT further believes that transmission facilities that have no phase protective relays subject to tripping on load are sufficiently uncommon that the proposed requirement would place a significant burden on Transmission Owners, Generator Owners, and Distribution Providers while providing limited benefit to the Planning Coordinators.
- Two commenters believe the standard should not be applicable to Distribution Providers. The SDT believes that since the approved PRC-023-1 includes Distribution Providers, the proposal to exclude Distribution Providers is outside the scope of the SAR for this project. However, the SDT further believes it is possible for a Distribution Provider to own a relay that protects a transmission facility, even if the Distribution Provider does not own the protected facility.
- One commenter observed there is much confusion about the registration of Planning Coordinators and suggests that while the Order proposes the Planning Coordinator perform this test, it could be assigned to the Regional Entity or the Reliability Coordinator (as in the SPCTF recommendation) and achieve the same result. The SDT notes the approved PRC-023-1 already assigns the Planning Coordinator with the requirement to determine which facilities must comply with PRC-023. The SDT believes there is no reason to revisit this issue.

One commenter believes it is not appropriate to modify Requirement R5, part 5.3 to include the Regional Entity as a recipient of the list of transmission facilities because the Regional Entity is the Compliance Monitor and Enforcement Authority for the NERC Reliability Standards and is not an operating entity. The SDT believes the role of the Regional Entity in compliance enforcement does not preclude a Reliability Standard from including Regional Entities as the recipients of data. The SDT further believes that providing the Regional Entity with the list of transmission facilities subject to Requirement R1 is the most direct way to address the Commission's objective to aid in the overall coordination of planning and operational studies among Planning Coordinators, Transmission Owners, Generator Owners, Distribution Providers, and Regional Entities.

Two commenters believe the criteria in Attachment B along with any necessary modifications to the associated requirement should be developed by a full drafting team. The Relay Loadability Standard Drafting Team that developed PRC-023-1 has been reconvened to address the directed modifications to the standard. The criteria that Planning Coordinators will use to determine which facilities must comply with PRC-023 were developed with the assistance of a "Blue Ribbon Panel" comprised of members from each region who are Subject Matter Experts in the area of Transmission Planning. Order No. 733 directs that the criteria in PRC-023 must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards, and input from the Blue Ribbon Panel provides additional expertise necessary to develop the directed modifications.

Organization	Yes or No	Question 6 Comment
Northeast Power Coordinating Council	No	Requirement R5 states that the Planning Coordinator will determine which facilities below 200kV are critical to the reliability of the Bulk Electric System by applying criteria defined in Attachment B, which is to be developed. Therefore, respondents cannot comment on Attachment B. Respondents reserve the right to

Organization	Yes or No	Question 6 Comment
		comment when Attachment B is available for review. Because the document has been presented to the industry without Attachment B, how will Attachment B be presented to the industry? Regarding sub-requirement 5.3, it must be revised to clarify that the Planning Coordinator will provide the list of facilities subject to the Standard to all of the TOs, GOs, and DPs registered in its footprint, not just to those entities that have facilities on the list.5.2 refers to "Part 1". As commented on previously in Question 5 and elsewhere, Part or Sub-requirement should be used for consistency.
Bonneville Power Administration	No	Requirement R5 is okay, but Part 5.1 adds an additional and useless extra burden to the applicable entities. The process that the Planning Coordinator is required by this part to have would almost certainly be to simply apply the criteria in Attachment B to lines and transformers operated below 200kV to determine if they are critical to the BES. Requiring documentation for such a trivial process results in increased paper work, additional preparation for an audit, and is a waste of everyone's time. We suggest deleting Part 5.1.
IRC Standards Review Committee	No	We disagree with modifying the requirement until the criteria is identified. Modifying the requirement now presumes the criteria will have no impact to the requirement. Contrarily, we believe that the criteria may cause some change to the requirement as well. The criteria in Attachment B along with any necessary modifications to the associated requirement should be developed by a full standards drafting team. Only the full standards drafting team could identify equally effective alternatives to the Commission's directives as they have made clear they allow in this Order and many others.
MRO's NERC Standards Review Subcommittee	No	As noted in Q1 above, a response would be conditional and depend on whether the criteria that will be established within Attachment B (see R5.1) are reasonable and apply to properly qualified faculties below 200 kV.In addition, the R5 requirement should include wording that limits the scope of the transmission facilities (line and transformer circuits) to be evaluated to only those transmission facilities that can be tripped by the relay settings subject to requirement R1. Requirement R5 should also qualify that only the transmission facilities that are "known" to be associated with the relay settings subject to requirement R1 need to be evaluated. If the SDT wants to better assure that the Planning Coordinator knows about all of the pertinent transmission facilities, then they should add a requirement that obligates Transmission Owners, Generator Owners, and Distribution Providers to provide the Planning Coordinator with a list of the transmission facilities that are associated with the relay setting subject to requirement R1.
E.ON U.S. LLC	No	See comments for item #1.
Transmission Access Policy Study Group	No	The proposed method of identifying facilities to which the standard will apply may be reasonable, though we cannot comment definitively until a draft of Attachment B is available. The standard should not be applicable to DPs, however. TAPS has been unable to find or think of an example in which a DP would have a load-

Organization	Yes or No	Question 6 Comment
		responsive transmission phase protection system, aside from a DP that is also a TO and has such a phase protection system because of its TO function. There is thus no reason to include DPs as potentially applicable entities.If the SDT retains DPs on the list of potentially applicable entities, it should at minimum clarify Requirement R5.3 to state that the Planning Coordinator will provide the list of facilities subject to the standard to all of the TOs, GOs and DPs registered in its footprint, not just to the entities who have facilities on the list. It is important that DPs who do not have facilities on the list have documentation from the Planning Coordinator demonstrating that fact.
American Transmission Company	No	As noted in Q1 above, an affirmative response would be conditional and depend on whether the criteria that will be established within Attachment B (see R5.1) are reasonable and apply to properly qualified facilities below 200 kV.In addition, the R5 requirement should include wording that limits the scope of the transmission facilities (line and transformer circuits) to be evaluated to only those transmission facilities that can be tripped by the relay settings subject to requirement R1. Requirement R5 should also qualify that only the transmission facilities that are “known” to be associated with the relay settings subject to requirement R1 need to be evaluated. If the SDT wants to better assure that the Planning Coordinator knows about all of the pertinent transmission facilities, then they should add a requirement that obligates Transmission Owners, Generator Owners, and Distribution Providers to provide the Planning Coordinator with a list of the transmission facilities that are associated with the relay setting subject to requirement R1.
TSGT System Planning Group	No	While we agree that the purpose of Requirement R5 is beneficial, there is much confusion about registration and responsibilities of Planning Coordinators. Though the FERC order proposes that planning coordinators perform the test developed herein, there is also flexibility in how NERC can achieve the same result. We believe that the Regional Entity (or the Reliability Coordinator, as was included in the System Protection and Control Task Force recommendation) should be the responsible functional entity for determining which elements operated at less than 200 kV need to meet Requirement R1. The Region was responsible for determining operationally significant facilities during the “Beyond Zone 3” process.
NV Energy	No	This approach is not yet an acceptable and effective method of meeting the directive of paragraph 69. Whether it becomes an acceptable and effective method of meeting the directive will depend on the content of Attachment B. I’ll reserve specific judgment and concerns until Attachment B is available for comment.
NPPD	No	Attachment B has not even been developed.
Idaho Power - System Protection	No	It is not acceptable or effective until Attachment B is completed and available for review.
Kansas City Power & Light	No	Do not agree with the approach in R5 and R5.1. This proposes to establish the criteria by which Reliability

Organization	Yes or No	Question 6 Comment
		Coordinators will determine facilities critical to the reliability of the BES. There are a variety of differing, and often complex, operating conditions that dictate the need for transmission facilities. The TPL standards require extensive studies of the transmission system be performed under steady state and dynamic conditions to understand and identify sensitive areas of the transmission system and enable Reliability Coordinators to identify flowgates in their respective regions. In light of the Reliability Coordinators awareness of transmission sensitivities through these studies, it seems unnecessary to dictate to the Reliability Coordinators additional criteria.In addition, in R5.3, do not agree that the Regional Entity be included as a recipient of the list of transmission facilities. By NERC definition, the Regional Entity is the Compliance Monitor and Enforcement Authority for the NERC Reliability Standards and is not an operating entity. It is inappropriate to include Regional Entities as an entity to provide this information outside of the audit process established by the NERC Rules of Procedure. By definition, in the NERC Reliability Terminology, the Regional Entity is a compliance enforcement agent and not an operating organization of the Bulk Power System, and, therefore, has no operating reason to obtain this information. See definition below:Regional Entity - The term ‘regional entity’ is defined in Section 215 of the Federal Power Act means an entity having enforcement authority pursuant to subsection (e)(4) [of Section 215]. A regional entity (RE) is an entity to which NERC has delegated enforcement authority through an agreement approved by FERC. There are eight RE’s. The regional entities were formed by the eight North American regional reliability organizations to receive delegated authority and to carry out compliance monitoring and enforcement activities. The regional entities monitor compliance with the standards and impose enforcement actions when violations are identified.
Independent Electricity System Operator	No	We are unable to assess its acceptability and effectiveness until Attachment B is developed.
Utility Services	No	The proposed method of identifying facilities to which the standard will apply may be reasonable, though we cannot comment definitively until a draft of Attachment B is available. The standard should not be applicable to DPs, however. We have been unable to find or think of an example in which a DP would have a load-responsive transmission phase protection system , aside from a DP that is also a TO and has such a phase protection system because of its TO function. There is thus no reason to include DPs as potentially applicable entities.If the SDT retains DPs on the list of potentially applicable entities, it should at minimum clarify Requirement R5.3 to state that the Planning Coordinator will provide the list of facilities subject to the standard to all of the TOs, GOs and DPs registered in its footprint, not just to the entities who have facilities on the list. It is important that DPs who do not have facilities on the list have documentation from the Planning Coordinator demonstrating that fact.
Long Island Power Authority	No	LIPA understands the drafting team’s rationale, however, believes that the proposed method in Attachment B

Organization	Yes or No	Question 6 Comment
		should be developed before providing comments.
Ameren	No	See our response to Question 1
American Electric Power	No	Please refer to our comment under question number 1. AEP reserves the right to provide additional comments once Attachment B has been drafted and supplied for industry review.
ERCOT ISO	No	ERCOT ISO respectfully asserts that the changes in this standard need more thorough discussion. This standard is incomplete without the Attachment B and the intent of the requirements is not explicitly clear. A standard drafting team (not a SAR SDT) needs to develop Attachment B through discussion of the entire process that will meet Order 733 directives. Attachment B is a critical component needed to assess R5 and provide further feedback. Requirement 5 needs to be reworded for clarity. The standard drafting team assigned to this project needs to work closely with the Reliability Coordination SDT (Project 2006-06), which is tasked with defining critical facilities or identifying criteria for developing a list of critical facilities.ERCOT ISO disagrees with the use of the phrase ‘facilities that are critical’ in this requirement. A requirement to create a list of critical facilities should not be addressed in this standard.
Duke Energy	No	We don’t have Attachment B yet, and the standard development timeline has the standard being submitted to FERC in March of 2011, which we believe is an unreasonable timeline.
Pepco Holdings, Inc - Affiliates	Yes	While philosophically we do not agree that this standard should apply to facilities below 100kV (i.e. facilities that are not defined as BES facilities) we believe that as long as a sound engineering methodology is developed and applied uniformly to identify those facilities critical to the reliability of the BES, then the revised wording is acceptable. Our response, however, is qualified based on being granted an opportunity to comment and vote on the methodology contained in Attachment B once it is developed.
FirstEnergy	Yes	Although we agree that R5 is the appropriate requirement to reference the criteria to be used, it is still to be determined if we agree with the criteria since it is still being developed.
Consumers Energy	Yes	We are concerned about the criteria still undergoing development, and will offer any relevant comments on that criteria when it is published.
Arizona Public Service Company	Yes	
Dominion Electric Market Policy	Yes	

Organization	Yes or No	Question 6 Comment
PacifiCorp	Yes	
Southern Company	Yes	
ComEd	Yes	
Manitoba Hydro	Yes	
ISO New England Inc.	Yes	
ITC Holdings	Yes	
	Yes	
Xcel Energy	Yes	
Wisconsin Electric		No comment

7. **Attachment A has been modified to address the directive in Paragraph 264 of Order no. 733. Do you agree that this is an acceptable and effective method of meeting this directive? If not, please explain.**

Summary Consideration:

Three-fourths of commenters believe the addition of section 1.6 in Attachment A is not an acceptable and effective method of meeting this directive. More than one-half of commenters believe that addressing the directive in the proposed manner will have a negative impact on reliability of the bulk electric system. The SDT agrees that addressing the directive in the manner proposed in the first posting will have the unintended consequence of impacting the dependability and security of certain protection systems. The SDT has revised the draft standard to address the following concerns noted by commenters.

- More than one-half of commenters noted that the proposed modification would require overcurrent fault detectors applied to supervise distance (impedance) elements to meet the relay loadability requirements which would have a detrimental impact on reliability. Setting these fault detectors to meet PRC-023 would restrict the ability of some distance elements to trip for end-of-zone faults, particularly on weak source systems. Eliminating the fault detector to avoid this concern would have the negative impact of making the protection system susceptible to undesired tripping during close-in faults on adjacent elements. Some commenters further noted that many microprocessor relays have inherent overcurrent supervision of impedance elements which cannot be disabled.
- Several commenters noted that the standard should apply to protective systems and not to individual components of protective systems and that compliance should be based on the ability of the protective system as a whole to meet the performance criteria established by the standard. Some commenters also noted that a clarification is required that "protective functions" applies only to those protective relay elements that would respond to non-fault or load conditions and could issue a direct trip.
- Some commenters noted their belief that the modification goes well beyond the Commission's concern and they proposed alternatives they believe would be equally effective and efficient approaches to addressing the Commission's reliability concerns.

In response to these concerns, in particular the negative impact on reliability associated with the proposed modification, the SDT has modified section 1.6 to include "1.6. Supervisory elements associated with current based communication assisted schemes where the scheme is capable of tripping for loss of communications." The SDT also modified the second bulleted item in section 2.1 to add the clause, "except as noted in section 1.6 above."

Some commenters expressed concern that the proposed modifications would require the overcurrent element in a switch-on-to-fault (SOTF) scheme to be subject to the relay loadability criteria, in conflict with the SPCTF technical paper that indicates there is no suggested loadability criterion if the voltage arming threshold is set low enough. Some commenters expressed concern that the proposed modification could negatively jeopardize reliability by resulting in an operational decision to open breakers upon loss-of-potential to a protection system. These commenters note that it would be preferable to leave the element in-service with fast tripping enabled for a fault until the loss-of-potential condition can be diagnosed and corrected. The SDT believes that the modifications to section 1.6 noted above remove the unintended consequence of the original modifications that could have required overcurrent functions in all SOTF schemes and overcurrent functions used to supervise distance elements to meet Requirement R1.

One commenter proposed that the requirement for setting supervising relays be 115 percent of the facility rating nearest to a 4-hour duration rather than the 150 percent threshold established for other phase protective relay settings that may limit transmission system loadability. The SDT believes that with the modifications to section 1.6 noted above the same setting requirements are appropriate for all protective functions listed under section 1 of Attachment A. The SDT believes this is appropriate and necessary to meet the reliability objective of this standard.

One commenter noted that this directive needs to be addressed by a full standard drafting team to adequately address this directive and identify equally effective alternatives to the Commission's directives. Another commenter recommended that the NERC System Protection and Control Subcommittee (SPCS) be engaged to investigate this issue and produce a white paper or other document describing any unintended consequences of implementing the FERC directive. The Relay Loadability Standard Drafting Team that developed PRC-023-1 has been reconvened to address the directed modifications to the standard. The SDT believes that the issues indentified in Order No. 733 can be addressed adequately by this SDT with industry stakeholder input through the NERC Standard Development Process. The NERC SPCS will be consulted to address the potential for unintended consequences associated with the proposed modifications to implementing the directives from Order No. 733.

Organization	Yes or No	Question 7 Comment
Pepco Holdings, Inc - Affiliates	No	We do not agree with the proposed wording of Section 1.6 of Attachment A which makes the standard apply to "Protective functions that supervise operation of other protective functions in 1.1 through 1.5". The standard should apply to "protective systems" not individual components of protective systems. Compliance should be based on the ability of the "protective system" as a whole to meet the performance criteria established by the standard. Delving into the details of individual scheme designs and supervising element operation goes well beyond the purpose and scope of this standard.In paragraph 251 of Order 733 the Commission "expressed concern that section 3.1 could be interpreted to exclude certain protection systems that use communications to compare current quantities and directions at both ends of a transmission line, such as pilot wire protection or current differential protection systems supervised by fault detector relays" and requested comment on "whether it should direct the ERO to modify section 3.1 to clarify that it does not exclude from the requirements of PRC-023-1 pilot wire protection or current differential protection systems supervised by fault detector relays." The Commission reiterated again in paragraphs 266, 268, and 270 their concern with not including supervising elements associated with "current differential schemes" to prevent them for operating on loss of communications. That being said, the proposed revision to Attachment A to include supervising elements for all protective functions in 1.1 through 1.5 goes well beyond addressing the Commission's concern. We believe the Commission's concern could be addressed by simply modifying Attachment A by deleting proposed section 1.6 and adding a new section 1.5.5 "Line current differential schemes, including supervising overcurrent elements". The SDT's current proposed wording for Section 1.6 would require the overcurrent element in a switch-on-to-fault scheme to be subject to the loadability criteria. However, the NERC SPCTF in their June 7, 2006 technical paper "Switch-on-to-Fault Schemes in the Context

Organization	Yes or No	Question 7 Comment
		of Line Relay Loadability" indicated there is no suggested loadability criterion if the voltage arming threshold is set low enough. Similarly, fault detectors which supervise distance elements would be subject to the loadability standard. However, there are no criteria established on how to set these elements, particularly on weak source systems, or zone 3 applications, where in order to reliably detect faults at the end of the zone of protection may require setting the supervising fault detector below 150% of line rating. The NERC SPCTF in their June 7, 2006 technical paper "Methods to Increase Line Relay Loadability" provided recommendations to increase loadability of distance elements through various techniques, such as the use of load encroachment elements or blinders, but does not specifically address setting of supervising elements. In fact, at present, there is no reliability standard requiring the use of supervising elements, and some newer microprocessor relays do not even employ supervising fault detectors on their distance elements. FERC in their Order 733 stated "As with our other directives in this Final Rule, we do not prescribe this specific change as an exclusive solution to our reliability concerns regarding the exclusion of supervising relay elements. As we have stated, the ERO can propose an alternative solution that it believes is an equally effective and efficient approach to addressing the Commission's reliability concerns."In summary, we believe that addressing the Commission's concern regarding supervising elements on current differential schemes, as described in our second paragraph above, would satisfy the intent of Order 733, while not imposing unnecessary additional restrictions on what has proven historically to be extremely reliable protection practices.
PSEG Companies	No	In attachment A was added a new requirement, item 1.6. We not agree with this. Sometimes these elements have to be set lower than the criteria. As long as the protection system as a whole does not trip the line, then that should meet the criteria. Individual elements that supervise tripping element should NOT be part of the standard.
Bonneville Power Administration	No	Here we have a situation where the standard is being compromised to satisfy FERC's misunderstanding of what a supervising relay is. In Paragraph 266, FERC gives an example of how a line differential relay works in an attempt to demonstrate why supervisory elements must not operate for load, but instead they clearly demonstrate their misunderstanding of the details of differential relay operation and what a supervisory relay is. Modern differential relays will disable the differential function upon loss of communications. If an overcurrent element is present, it would be used for backup protection, not as a supervisory element. If an overcurrent element were used to supervise a differential element, the sensitivity of the differential relay would be lost and the result would be a simple overcurrent relay. FERC's misunderstanding has resulted in the improper addition of supervisory relays in Attachment A, Section 1. Sometimes supervisory relays must be set below maximum loading to obtain the purpose they were intended for. For example, it is often necessary to set overcurrent supervision of distance relays below the maximum load current of the line so that they will operate for remote faults. This modification to Attachment A would prohibit that action and make it impossible to set the supervisory relays to comply with the standard and still provide adequate protection. The

Organization	Yes or No	Question 7 Comment
		modification to Attachment A is unacceptable.
FirstEnergy	No	FirstEnergy supports applying PRC-023 to certain supervising relays, such as overcurrent relays that are enabled only when another (usually communications based) scheme is out of service, or overcurrent relays that are ANDed with current differential elements that can trip by themselves if the communications path used by the current differential scheme is compromised. However, it is not clear that a 150% factor is the correct one to use in this case. Our understanding is that 150% is a combination of an error factor (widely utilized by industry) of 15% plus a 35% margin to approximate a 15 minute interval rating to give operators time to react to adverse system conditions. It is unclear that this extra 35% margin is needed for these supervising relays, when the reliability goal is to prevent relays being continuously picked-up. We recommend that the standard utilize a 115% margin (rating duration nearest 4 hours) for these types of supervising relays and that this would be adequate to meet the Commission's stated reliability concerns.However, there are several other types of schemes that utilize supervising relays where applying PRC-023 would be detrimental to the reliability of the bulk power system. One widely used case is the supervision of an impedance relay when there is no communications scheme involved. There are cases where an impedance element/relay which is set per PRC-023, correctly operates for a fault it is intended to see, but that the actual current value will be on the order of the line rating, which will result in the scheme not operating if the supervising relay is set as the commission proposes. The alternative for these types of schemes is to remove the supervision from the scheme, which will result in the scheme operating purely on the impedance element, which is exactly the reliability concern that the Commission is trying to address with this directive. However, many microprocessor relays have inherent overcurrent supervision of impedance elements which cannot be disabled, adding to the complexity of the issue. Since this is a fairly complex theoretical/technical issue, we recommend that the NERC System Protection and Control Subcommittee (SPCS) investigate this issue and produce a white paper or other document describing any unintended consequences of implementing the FERC directive. The work of the SPCS could also consider equally effective alternatives to meeting the Commission’s directive.
IRC Standards Review Committee	No	We believe this directive needs to be addressed by a full standards drafting team to ensure the precise language is crafted to adequately address the directive. Furthermore, we believe only the full standards drafting team could identify equally effective alternatives to the Commission’s directives as they have made clear they allow in this Order and many others.
MRO's NERC Standards Review Subcommittee	No	In Order 733, the Commission cites in footnote 186 (p. 161) the definitions of dependability and security, two components of reliability for protective relays. The Commission did not recognize that the two tend to be mutually exclusive. Raising dependability (making sure breakers trip during a fault) can sacrifice some degree of security (tripping more than is needed).Historically, protection engineers have been biased toward dependability to ensure the safety of people and equipment. The exclusions allow that to happen. These are contingency scenarios where protective schemes are compromised. For a second contingency, the

Organization	Yes or No	Question 7 Comment
		dependability is at risk if fast tripping is not employed. By removing the exclusion, reliability could be negatively jeopardized. For example, an operational decision to open breakers will be needed for loss of potential. The corollary would be leaving the element in service with fast tripping enabled for a fault until the loss of potential condition can be diagnosed and corrected.
Dominion Electric Market Policy	No	Dominion disagrees with the directive to the ERO to revise section1 to include supervising relays for example, the fault detectors that we have in electromechanical distance schemes. The impedance relays are set to meet Reliability Standard PRC-023-1 while the overcurrent fault detector does not trip the transmission line breaker(s) independently of the impedance relays. Simultaneously meeting full allowance of the line terminal emergency loading limit and providing adequate sensitivity for detecting line faults with this fault detector will simply not be achievable for many of our lines.
E.ON U.S. LLC	No	E.ON U.S. requests a clarification of “protective functions” such that it applies only to those protective relay elements that would respond to non-fault or load conditions, and could issue a direct trip, upon operation, during a loss of communication or loss of potential condition.
American Transmission Company	No	In Order 733, the Commission cites in footnote 186 (p. 161) the definitions of dependability and security, two components of reliability for protective relays. The Commission did not recognize that the two tend to be mutually exclusive. Raising dependability (making sure breakers trip during a fault) can sacrifice some degree of security (tripping more than is needed).Historically, protection engineers have been biased toward dependability to ensure the safety of people and equipment. The exclusions allow that to happen. These are contingency scenarios where protective schemes are compromised. For a second contingency, the dependability is at risk if fast tripping is not employed. By removing the exclusion, reliability could be negatively jeopardized. For example, an operational decision to open breakers will be needed for loss of potential. The corollary would be leaving the element in service with fast tripping enabled for a fault until the loss of potential condition can be diagnosed and corrected
PacifiCorp	No	Paragraph No. 264 directs a revision to Section 1 of Attachment A in order to include supervising relay elements. This change as currently written requires further clarification to meet this directive. For example, a Distance element is commonly supervised by a phase overcurrent element (Fault detector). If this change suggests that the overcurrent element has to be set above maximum load, then PacifiCorp disagrees with the modification. The fault detector will not trip the line by itself; it operates to qualify the distance element assertion. It is our standard practice to set this element above load where possible, but without restricting the reach of the distance element. This means that if the fault current at the maximum reach of the distance element is below load, setting the fault detector above load will restrict the reach of the distance element- this would compromise the protection scheme. In microprocessor relays where Load encroachment is used this is even more critical. The Load encroachment function will prevent the distance element from operating in the

Organization	Yes or No	Question 7 Comment
		load region and a fault detector setting that is sensitive enough can be used safely without the need to set it above load current to enhance the distance element reach.
Southern Company	No	The language that has been added to PRC-023 related to the inclusion of protection elements (fault detectors) supervising protection functions that are subject to the PRC-023-2 requirements is not appropriate and will likely decrease the reliability of the BES for the following reasons:- The tripping logic utilizing these elements is an AND function, it takes distance element AND the fault detector (FD) to trip. Since all distance elements meet the loadability criteria, it is not necessary to also ensure FD meet hese requirements.- Setting FD above nominal load point would unnecessarily reduce sensitivity of distance element and in many cases eliminate the distance element’s ability to protect the very system element it is designed and intended to protect- It would require very expensive communications based relay schemes to replicate this lost protection if it is even possible to do so; a long radial line is one instance where it would not be possible- Eliminating the FD would actually reduce Security and Dependability in electromechanical schemes- There is a whole generation of microprocessor based relays that it is not possible to eliminate the FD; to effectively take it out of service, one would have to set it to the most sensitive setting which would violate the loadability criteria- Relays at terminals with high SIR, a weak source system, and line with large conductors where the far end fault current may be smaller than maximum line current (similar to Exception 6 of the Relay Loadability Exceptions: Determination and Applications of Practical Relaying Loadability Ratings, Version 1.1 published November 2004 by the System Protection and Control Task Force of NERC)- Faults with low power factor could present a similar magnitude of line current as normal high power factor load currents
NPPD	No	Please remove Attachment A, R1.6. "Protective functions that supervise operation of other protection functions in 1.1 through 1.5.". If you do not remove R1.6 you must provide a detailed explanation of what supervise operation means and give examples. Utilities have thousands of relays that have imbedded fault detective supervision overcurrents for phase distance elements that are set at 0.5 amps or some similar value. This can not be changed. From your requirement these utilities would have to replace all of these relays or we would have to lower the Facality rating to 0.5 amp secondary/150%. You are also stating that if we have an external phase overcurrent fault detector that supervises a phase distance relay that this fault detector must now have to meet Requirement 1. This is an unacceptable requirement if this is your intent. You are putting the system at risk if this is your intent. We must set our relays to protect the line. We must also set fault detectors to pickup for all faults considering N-1 conditions at a minimum where the strongest source must be remove and the relays must still clear the fault. Please do not lose focus of the purpose: "Protective relay settings shall be set to reliably detect all fault conditions and protect the electrical network from these faults". If you have questions on my comments feel free to contact me. Steve Wadas, NPPD, 402 563 5917 Wk.

Organization	Yes or No	Question 7 Comment
Consumers Energy	No	The supervising elements addressed within this change may fundamentally be unable to be set in accordance with the requirements of PRC-023, while still permitting the Protection System to function properly for fault conditions. The supervising element is usually present to assure that a distance element does not operate inadvertently for close-in zero-voltage faults near the relay location in the non-trip direction, but does not, by itself, produce a trip. We appreciate that NERC must respond to this directive, but believe that the change, as expressed, will be detrimental to reliability.
ComEd	No	1) Certain relay elements may be thought to be "supervising relay elements", when their function is specific and more limited. A very common example would be a phase overcurrent relay that is required to actuate along with a phase distance relay to cause a trip. In many applications, the phase overcurrent relays function is only to assure that the phase distance relay will not cause a trip when a line is taken out of service and no potential restraint is applied to the phase distance relay. Thus, loadability of the phase overcurrent relay is not a concern. Raising the level of the overcurrent element may negatively impact the fault detecting ability of the two relays. This is perhaps a limited function supervising relay element. It is complementary to the phase distance relay which provides the necessary loadability. 2) Although we don't employ out of step tripping, it would seem that the argument for the overcurrent element of an out of step tripping scheme would be the same as for the phase distance element. 3) Are there supervisory elements for switch onto fault schemes that could limit loadability? 4) In our experience, relays that supervise overcurrent relays are typically specifically designed to provide loadability in order to allow the overcurrent relay to provide greater sensitivity without worrying about its loadability. Thus this requirement would limit the use of such a scheme. 5) FERC's main example seems to refer to an old style of current differential relaying scheme that is likely not very widely applied. Most modern current differential schemes use digital communications and will not trip on loss of communications regardless of the settings of any elements that may be considered to be supervisory relay elements. The drafting team should consider modifying 1.6 of Attachment A to clarify and more specifically address the FERC concern. Three suggestions are as follows: 1) 1.6. Protective functions that supervise operation of other protective functions in 1.5. This is required for communications aided protection schemes in 1.5 only when those schemes require communication channel integrity to maintain scheme loadability. 2) 1.6. Protective functions that supervise operation of other protective functions in 1.2 through 1.5. This is required for communications aided protection schemes in 1.5 only when those schemes require communication channel integrity to maintain scheme loadability. 3) 1.6. Protective functions that supervise operation of other protective functions in 1.2 through 1.5.
Manitoba Hydro	No	Item 1.6 in Attachment A is not necessary. If the protection functions in 1.1 through 1.5 already meet all the

Organization	Yes or No	Question 7 Comment
		loadability requirements, the facility would not trip under heavy load condition by the supervising protection element alone. The directive in paragraph 264 of Order 733 seems to deal with the supervising protection element on the current differential scheme only. It is still arguable whether it is better to allow tripping of the line or restrain from tripping during loss communication and heavy loading condition.
Wisconsin Electric	No	We strongly disagree with this change. Applying the loadability requirement to supervisory functions in protection system will have an extremely negative effect on BES reliability. With this change, protection systems will be less dependable, resulting in increased probability of a failure to detect a system fault. This change should not be implemented.
Long Island Power Authority	No	LIPA believes that the new wording in 1.6 Attachment A is unnecessary since the existing wording already complies with the FERC order p.264. Supervisory functions are already part of the protective functions 1.1 through 1.5. Also, this new wording will be subject to varied interpretation and create more confusion.
Ameren	No	In attachment A - 1.6 is not a tripping function - it's a supervisory function - it in itself does not trip which is the description of '1' therefore needs to be elsewhere if kept.
American Electric Power	No	AEP requests some clarifying information regarding what is envisioned for 1.6 of Attachment A.
ITC Holdings	No	It appears from the new 1.6 (Attachmnt A) that fault detectors must meet loadability requirements. These do not trip and must not be included in PRC023. We will not be able to adequately protect longer lines in weak areas with this requirement in place.
	No	Removal of exclusion 3.1 in Att. A, will lead to reduced reliability because an operational decision to open breakers will be needed for loss of potential conditions. The corollary would be leaving the element in service with fast tripping enabled for a fault until the loss of potential condition can be diagnosed and corrected.
South Carolina Electric and Gas	No	Item 1.6 of Attachment A needs to be clarified. If the intent is to include protective functions such as fault detectors then this could possibly lead to relay sensitivity problems when switching contingencies create weaker systems than normal and a line is faulted. It is unclear why supervisory functions are considered if the protective functions they supervise will operate in compliance with R1
Xcel Energy	No	Xcel Energy disagrees with the inclusion of the supervising functions in part 1.6 of Section 1 in Attachment A. Supervising functions in protection schemes provide security for non-power system fault events and are not the principal elements for scheme operation. Only principal elements should be considered in the requirements of the PRCâ€'023 standard.Functions such as overcurrent fault detectors provide security in the

Organization	Yes or No	Question 7 Comment
		event of a failed potential source or blown secondary fusing. Fault detectors must be set below the minimum end-of-zone fault with a single system contingency in effect. It is common industry practice to set these functions at 60â€‘80% of these minimum fault levels and may necessitate a setting that is below the Facility Rating of a circuit.Increasing the setpoint of an overcurrent fault detector above the Facility Rating will limit the coverage of the protection system and may impact the system's ability to protect the electrical network from Faults. An alternative is to limit the Facility Rating as allowed in Requirement R1.12. However limiting this Facility Rating places an arbitrary constraint on the circuit and is not justifiable for a non-principal function. Eliminating the fault detector is not possible in the case of some microprocessor-based relays and if it is possible, reduces the security of the protective scheme.
Duke Energy	No	Attachment A has added 1.6 stating "Protective functions that supervise operation of other protective functions" is included in the standard. We would argue that it is not reasonable to include overcurrent fault detectors used to supervise distance elements or breaker failure schemes. These relays provide security to the protection scheme, such as for loss of potential conditions, and do not trip on their own. If these relays would be set per the standard, it would render the schemes ineffective for many fault conditions. In the case of electromechanical schemes, the supervising relay could be removed from service which could make the protection scheme misoperate. In the case of microprocessor relays, the supervising relay is embedded in logic and can't be removed.
TSGT System Planning Group	Yes	As we interpret the changes to Attachment A they are acceptable. However, there appears to be uncertainty about the intent of the drafting team. We interpret the change to 1.6, in conjunction with 2.1, to allow setting impedance relay fault detector supervisory elements at levels below load current levels. This understanding comes from the realization that the fault detector elements by themselves do not "trip with or without time delay, on load current," a requirement described in 1. The fault detector elements can cause tripping on their own, but only for conditions of loss of potential or loss of communications, which are both excluded from the loadability requirements as steted in 2.1.If Tri-State's interpretation of the intent of Attachment A, Sections 1, 1.6, and 2.1 is incorrect, then we do not agree that this is an acceptable and effective method of meeting this directive. There are many protection system locations in our system that require the fault detector supervision elements to be set below load current levels in order for backup impedance relays to operate securely in the event of loss of potential and to operate dependably for remote faults that inherently have low fault current magnitudes.
Idaho Power - System Protection	Yes	The order has been met, but there is significant concern about the inclusion of supervisory elements in protective systems. A supervisory element is not performing a tripping function. As stated in Attachment A "This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:...". Supervisory elements, used properly, do not trip for load current.

Organization	Yes or No	Question 7 Comment
Northeast Power Coordinating Council	Yes	
Arizona Public Service Company	Yes	
NV Energy	Yes	
Kansas City Power & Light	Yes	
Independent Electricity System Operator	Yes	
ISO New England Inc.	Yes	

8. **Do you agree that the SDT has addressed the remaining directives: Paragraph 284 to remove the footnote and Paragraph 283 to modify the implementation plan for sub-100 kV facilities (by revising the Effective Date section of the standard)?**

Summary Consideration:

The SDT agrees with several commenters about the proposed language for Effective Dates and has changed the language to the following:

5.1. Requirement R1: the first day of the first calendar quarter after applicable regulatory approvals, except as noted below.

5.1.1 For the addition to Requirement R1, criterion 10, to set transformer fault protection relays and transmission line 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, the first day of the first calendar quarter 12 months after applicable regulatory approvals.

5.1.2 For supervisory elements as described in Attachment A, section 1.6, the first day of the first calendar quarter following 24 months after applicable regulatory approvals.

5.2. Requirements R2 and R3: the first day of the first calendar quarter after applicable regulatory approvals.

5.3. Requirements R4 and R5: the first day of the first calendar quarter following 24 months after applicable regulatory approvals.

5.4. Requirement R6: the first day of the first calendar quarter 18 months after applicable regulatory approvals.

5.5. Requirement R7: the first day of the first calendar quarter after applicable regulatory approvals.

One comment addressed the issue of a reliability standard superseding previous agreements between registered entities and NERC. The SDT believes that, by removing the footnote, the standard does not supersede previous agreements because the latest due date for mitigation of temporary exceptions under the Beyond Zone 3 review was December 31, 2008. Removal of the footnote has no bearing on previous agreements given that all temporary exceptions have expired.

To address the need for entities to meet the requirements of the standard for facilities identified by the Planning Coordinator in the future, the SDT added a new requirement (R7).

Organization	Yes or No	Question 8 Comment
Pepco Holdings, Inc - Affiliates	No	We agree with the removal of the footnote regarding temporary exceptions. However, there appears to be a contradiction between the effective dates for sub 200kV facilities noted in section 5.1.2 (39 months following regulatory approvals) and 5.1.3 (24 months after being notified by its Planning coordinator). If the planning coordinator takes the full 18 months to determine the R5 list (per effective date section 5.2) and the TO has 24 months after that to comply, that would be 42 months following regulatory approval, which is in conflict with the 39 month requirement in 5.1.2. Since the list of sub 200kV facilities may change from year to year, it

Organization	Yes or No	Question 8 Comment
		would seem prudent to make the effective date for those facilities always tied to a defined interval following being notified by the Planning Coordinator and eliminate the 39 month requirement for sub 200kV facilities from 5.1.2. Also, since the Attachment B methodology has not yet been determined, it is unclear how many sub 200kV facilities may fall under these requirements. As such, one cannot yet determine if the proposed 24 months would be sufficient. We propose at least a 36 month interval until the methodology is finalized and the magnitude of the scope better defined. In addition, if supervising elements are included in the standard in some form, an implementation schedule (i.e. appropriate effective dates) need to be developed based on this significant increase in scope and number of facilities to be reviewed.
Bonneville Power Administration		5.1.2 and 5.1.3 both apply to the same systems and should be combined into one sub-requirement. Also, since the date of the applicable regulatory approval is now established, please consider replacing the cryptic phrase “at the beginning of the first calendar quarter 39 months following applicable regulatory approval” with an actual date.
IRC Standards Review Committee	No	While we agree removing the footnote is straight forward and addresses one Commission directive, we believe the other directives need to be addressed by a full standards drafting team to ensure the precise language is crafted to adequately address the directives. Furthermore, we believe only the full standards drafting team could identify equally effective alternatives to the Commission’s directives as they have made clear they allow in this Order and many others. In particular, we believe that only a full drafting team could adequately assess if any additional time will be needed to comply with the standard for sub-100 kV facilities particularly when we consider there are some outstanding issues including a regional entity’s critical facilities list identified in Question 1. Also, we are unable to assess if the two directives are fully addressed absent a proposed implementation plan.
Kansas City Power & Light	No	It is inappropriate for this standard to supersede any other agreements and the provisions of those agreements that have been established between NERC and Registered Entities. The footnote made it clear those agreements would continue to be honored. Recommend the SDT reinstate the principles established by the footnote directly into the Effective Dates section to recognize the authority of those agreements.Agree with the effective dates of 18 months after applicable approvals for R5 and for 24 months after notification by the Planning Coordinator of a new critical facility.
Independent Electricity System Operator	No	We are unable to comment on this in the absence of a proposed implementation plan.
E.ON U.S. LLC	No	Cannot assess the impact until Attachment B is developed and commented sections above are clarified.

Organization	Yes or No	Question 8 Comment
Manitoba Hydro	No	Even though this version of the standard does seem to have addressed Paragraph 284 of Order 733, we still do not agree with the uniform effective date without taking into consideration how many critical circuits or equipment could be added for an individual utility.
American Electric Power	No	It is unclear how much time a TO, GO, or DP would have to implement the changes based on the results of the analysis by the Planning Coordinator. In addition, the Effective Date section is a one-time event upon regulatory approval. What are the on-going implementation expectations? There should be some allowed lead beyond initial implementation after facilities are identified by the Planning Coordinator.
ITC Holdings	No	The new effective dates for 5.1.2 will for the most part be ok. Some of these below 200 kV lines will have to be reconstructed to be able to have adequate protection and meet the required loadability. It will be difficult to do this in 39 months. We suggest a mitigation program be required for those lines that will be difficult to meet the 39 month deadline.
Duke Energy	No	Until we see the criteria for Attachment B, we can't agree that 39 months is sufficient time.
ISO New England Inc.	No	While we agree removing the footnote is straight forward and addresses one Commission directive. In particular, we believe that only a full drafting team could adequately assess if any additional time will be needed to comply with the standard for sub-100 kV facilities particularly when we consider there are some outstanding issues a regional entities critical facilities list identified in Question 1. Also, we are unable to assess if the two directives are fully addressed absent a proposed implementation plan.
Long Island Power Authority	No	
Northeast Power Coordinating Council	Yes	
FirstEnergy	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
Dominion Electric Market Policy	Yes	
American Transmission	Yes	

Organization	Yes or No	Question 8 Comment
Company		
Southern Company	Yes	
TSGT System Planning Group	Yes	
NV Energy	Yes	
NPPD	Yes	
Consumers Energy	Yes	
Idaho Power - System Protection	Yes	
ComEd	Yes	
Ameren	Yes	
Xcel Energy	Yes	
Wisconsin Electric		No comment

9. Do you agree that the scope of the proposed standards action addresses the directive or directives?

Summary Consideration:

The SAR shows the directive from P. 162 as part of Phase I to be implemented by March 18, 2011. However, some commenters indicated this directive should be included in Phase III since it deals with the subject of relay operations due to power swings. The SDT reviewed the SAR and determined a modification to the SAR is unnecessary because the SDT already has considered "islanding" strategies that achieve the fundamental performance for all islands as part of Phase I, although following this consideration the SDT agrees islanding strategies are best addressed as part of the new standard that will be developed in Phase III of the project.

Several commenters indicated that the directive from P. 224 is missing from the detailed section of the SAR, but is included in the table in the back of the SAR. This was an error in the SAR and the SDT has added this directive to the detailed section of the SAR for Phase I. The new Requirement R5 will support collection of the data necessary for the ERO to address the directive. The ERO will provide the data upon request, but outside of PRC-023.

Organization	Yes or No	Question 9 Comment
FirstEnergy	No	i. The SAR shows the directive from P. 162 as part of Phase I to be implemented by March 18, 2011. However, this directive should be included in Phase III since it deals with the subject of relay operations due to power swings. ii. The directive from P. 224 is missing from the detailed section of the SAR, but is included in the table in the back of the SAR. iii. As mentioned in our response to Question 7, we do not agree with how the project is proposing to address the P. 264 directive.
Response: The SDT reviewed the SAR and determined a modification to the SAR regarding P.162 is unnecessary because the SDT already has considered "islanding" strategies that achieve the fundamental performance for all islands as part of Phase I, although following this consideration the SDT agrees islanding strategies are best addressed as part of the new standard that will be developed in Phase III of the project. **The reference to P.224 was omitted from the detailed section of the SAR by error. The SDT has added this directive to the detailed section of the SAR for Phase I. The new Requirement R5 will support collection of the data necessary for the ERO to address the directive. The ERO will provide the data upon request, but outside of PRC-023.** **Please see our response above to your comment regarding P.264**		
IRC Standards Review	No	We largely believe the scope will allow the drafting team to address the directives. However, we request that

Organization	Yes or No	Question 9 Comment
Committee		the scope be modified to make clear that the drafting team may use equally effective alternatives to address the Commission's directives per the Commission in this order and other orders such as Order 693.There is a discrepancy between the entities listed in the Applicability Section and those checked off in the SAR. The latter indicates that the SAR is also applicable to the Reliability Coordinator, which we do not believe is appropriate.
Response: The Standards Process Manual states that a Standard Authorization Request (SAR) is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified standards or the benefit of retiring one or more approved standards. This SAR is specific to addressing regulatory directives in Order No. 733. The SAR should only contain the scope and not include how the directives will be met as it is understood that the directives may be met in an equally effective alternative. **The SDT notes that the SAR contains a list of entities that could potentially be included in the standard, but it is not necessary that the SDT include each entity in the applicability section of the standard.**		
MRO's NERC Standards Review Subcommittee	No	It addresses the directives per the letter of the order; however, it is not necessarily improving reliability.
Response: Thank you for your input.		
E.ON U.S. LLC	No	See commented sections above. Also, the directive identified in Paragraph 224 was not included in the detailed description or highlighted in Attachment 1 of the SAR. However it was included in the proposed modifications as R4.
Response: The reference to P.224 was omitted from the detailed section of the SAR by error. The SDT has added this directive to the detailed section of the SAR for Phase I. The new Requirement R5 will support collection of the data necessary for the ERO to address the directive. The ERO will provide the data upon request, but outside of PRC-023. Requirement R5 does not address the directive in P.224 directly as this is a directive to the ERO to provide data upon request. Since the data is subject to audit, the SDT interprets this to mean that the ERO must gather and have continuously available a list of facilities using Requirement R1 criterion 12. Requirement R5 ensures that the data is available.		
TSGT System Planning Group	No	As stated in our earlier comments, we believe that some proposals exceed the directives. It is also not clear how p 162 was addressed in PRC-023-2 as indicated on SAR-3.
Response: The SDT notes that this directive is not addressed in PRC-023-2. The SDT considered "islanding" strategies that achieve the fundamental performance for all islands as part of Phase I, although following this consideration the SDT agrees islanding strategies are best addressed as part of the new standard that will be developed in Phase III of the project.		

Organization	Yes or No	Question 9 Comment
NPPD	No	
American Electric Power	No	Refer to our comment under question 1.
Response: Please see our response above to your comment on Question 1.		
Pepco Holdings, Inc - Affiliates	Yes	While the scope of the proposed standards action addresses the directive(s) outlined in FERC Order 733 we believe that there are two significant issues that need to be much more thoroughly investigated before being included. Those areas are the inclusion of supervising elements in the existing relay loadability standard and the development of any new standard that would "require the use of protective relay systems that can differentiate between faults and stable power swings and when necessary phase out protective relay systems that cannot meet this requirement."
Response: In response to industry concerns regarding supervisory elements, in particular the negative impact on reliability associated with the proposed modification, the SDT has modified section 1.6 to state: "1.6. Supervisory elements associated with current based communication assisted schemes where the scheme is capable of tripping for loss of communications." The SDT also modified the second bulleted item in section 2.1 to add the clause, "except as noted in section 1.6 above." The NERC SPCS will be consulted to address the potential for unintended consequences associated with the proposed modifications to implementing the directives from Order No. 733. **The issues related to power swings will be addressed in Phase III of this project according to the SAR, and the NERC System Protection and Control Subcommittee (SPCS) and Transmission Issues Subcommittee (TIS) are jointly developing a paper, *Issues Related to Protective System Response to Power Swings*.**		
American Transmission Company	Yes	It addresses the directives per the letter of the order; however, it is not necessarily improving reliability.
Response: Thank you for your input.		
Kansas City Power & Light	Yes	Agree that the SDT has made revisions that attempted to address the FERC directives. Do not agree with all the proposals by the SDT as indicated by the comments regarding questions 1 through 8.
Response: Please see our responses above to your comment on Questions 1 through 8.		
Independent Electricity System Operator	Yes	As indicated in our comment submitted under Q1, there is a discrepancy between the entities listed in the Applicability Section and those checked off in the SAR. The latter indicates that the SAR is also applicable to the RC, which we do not believe is required.

Organization	Yes or No	Question 9 Comment
Response: The SDT notes that the SAR contains a list of entities that could potentially be included in the standard, but it is not necessary that the SDT include each entity in the applicability section of the standard.		
Northeast Power Coordinating Council	Yes	
Bonneville Power Administration	Yes	
Dominion Electric Market Policy	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Southern Company	Yes	
NV Energy	Yes	
Consumers Energy	Yes	
Idaho Power - System Protection	Yes	
ComEd	Yes	
Manitoba Hydro	Yes	
ISO New England Inc.	Yes	
Long Island Power Authority	Yes	
ITC Holdings	Yes	
	Yes	

Organization	Yes or No	Question 9 Comment
Duke Energy	Yes	
Wisconsin Electric		No comment

10. Can you identify an equally efficient and effective method of achieving the reliability intent of the directive or directives?

Summary Consideration:

Many comments were offered regarding the directives in Paragraph 150 of Order 733 that NERC "develop a Reliability Standard that requires the use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement," and suggested that this subject either needs to be addressed via modification to TPL-001 or that it needs further study. It is notable that this issue is to be addressed in Phase III of this project according to the SAR, and that the SPCS and TIS are jointly developing a paper, *Issues Related to Protective System Response to Power Swings*.

Many other commenters repeated comments that were offered in response to other questions.

Organization	Yes or No	Question 10 Comment
American Electric Power	No	Not at this time, but AEP would like to consider all viable options throughout the standard development process.
Response: Thank you for your input.		
FirstEnergy	No	Regarding the directive of Par. 264, since this is a fairly complex theoretical/technical issue, we recommend that the NERC System Protection and Control Subcommittee (SPCS) investigate this issue and produce a white paper or other document describing any unintended consequences of implementing the FERC directive. The work of the SPCS could also consider equally effective alternatives to meeting the Commission's directive.
Response: The NERC SPCS will be consulted to address the potential for unintended consequences associated with the proposed modifications to implementing the directives from Order No. 733.		
IRC Standards Review Committee	No	We are not prepared at this time to offer equally efficient and effective alternatives. Rather, we believe this is the purpose for convening a full drafting team and that the drafting team should propose their alternatives.
Response: The Relay Loadability Standard Drafting Team that developed PRC-023-1 has been reconvened to address the directed modifications to the standard. The SDT believes that the issues identified in Order No. 733 can be addressed adequately by this SDT with industry stakeholder input		

Organization	Yes or No	Question 10 Comment
through the NERC Standard Development Process.		
Dominion Electric Market Policy	No	Since there is no question that asks if there are other concerns with this draft, I will add one here..... R2 should be modified to read “The Each Transmission Owner, Generator Owner, or and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, Settings1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall forward this information to the Planning Coordinator, Transmission Operator, and Reliability Coordinator. The burden for acknowledging agreement or specifying reasons for disagreement should reside with the Planning Coordinator, Transmission Operator, and Reliability Coordinator. Suggest SDT develop additional requirements similar to those in FAC-008 @ R2 and R3.
Response: This proposal is outside the scope of the SAR that is intended to limit the project to addressing the directives in Order No. 733. This suggestion could be made when the standard is reviewed during the required 5-year review of the standard.		
ISO New England Inc.	No	We are not prepared at this time to offer equally efficient and effective alternatives. Rather, we believe this is the purpose for convening a full drafting team and that the drafting team should propose their alternatives.
Response: The Relay Loadability Standard Drafting Team that developed PRC-023-1 has been reconvened to address the directed modifications to the standard. The SDT believes that the issues indentified in Order No. 733 can be addressed adequately by this SDT with industry stakeholder input through the NERC Standard Development Process.		
NV Energy	No	NERC's proposed Phase I, II, II process seems reasonable.
Response: Thank you for your support.		
ComEd	No	No, other than the comments provided for question 7.
Response: Please see our responses above to your comment on Question 7.		
Dominion Electric Market Policy	No	
PacifiCorp	No	
Southern Company	No	

Organization	Yes or No	Question 10 Comment
NPPD	No	
Idaho Power - System Protection	No	
Kansas City Power & Light	No	No other comments.
ITC Holdings	No	
	No	
Northeast Power Coordinating Council	No	
Duke Energy	No	
Bonneville Power Administration	No	
TSGT System Planning Group	Yes	We included specific proposals in our comments to questions 2, 4, 5, and 6.
Response: Please see our responses above to your comment on Questions 2, 4, 5, and 6.		
Manitoba Hydro	Yes	The effective date can be dependent upon how many critical circuits or equipment are identified for each individual company.
Response: The SDT considered this possibility in developing effective dates for each requirement in the standard.		
Consumers Energy	Yes	NERC should, again, oppose the FERC directive in paragraph 264, since, as explained above, this directive is both unnecessary and detrimental to reliability.
Response: In response to industry concerns, in particular the negative impact on reliability associated with the proposed modification, the SDT has modified section 1.6 to state: “1.6. Supervisory elements associated with current based communication assisted schemes where the scheme is capable of tripping for loss of communications.” The SDT also modified the second bulleted item in section 2.1 to add the clause, “except as noted in section 1.6 above.”		

Organization	Yes or No	Question 10 Comment
Long Island Power Authority	Yes	Involving industry working groups such as IEEE, EPRI, etc who have proven technical experts will also help in effectively achieving reliability.
Response: The NERC System Protection and Control Subcommittee (SPCS) will be consulted to address the potential for unintended consequences associated with the proposed modifications to implementing the directives from Order No. 733.		
Pepco Holdings, Inc - Affiliates	Yes	Regarding the response of protective relay systems to stable power swings, Draft 5 of TPL-001-2 Requirement R4 (stability assessment) section 4.3.1 requires a contingency analysis be performed which includes “tripping of transmission lines and transformers where transient swings cause protection system operation based on generic or actual relay models.” Therefore the impact of power swings on relay operation is already addressed in TPL-001. If the tripping of a line is identified during this study phase the impact of the line trip is assessed to ensure the system meets the performance criteria identified in Table 1. If not, mitigating measures would be required, such as modifying that protection scheme to prevent its operation during a stable power swing. However, this would be done on a case by case basis when identified. This seems a much more prudent approach than to require “all protection systems be modified to prevent operation during stable power swings.” That would be similar to requiring the re-conductoring all lines so that they could never experience an overload. Also, Appendix F of the “PJM Relay Subcommittee Protective Relaying Philosophy and Design Standards” employs a methodology to address relay response during power swings by calculating a transient load limit for the relay instead of just the steady state limit identified in PRC-023. The relay loadability is evaluated at the maximum projection along the +R axis (the most susceptible point for swings to enter) rather than at a 30 degree load angle. Various multiplying factors are used to account for the relay operating time delay. This methodology of calculating relay transient loadability limits, which was developed by the PJM Relay Subcommittee over 30 years ago, has worked extremely well in eliminating relay operations during stable power swings. In summary, there are other methods to evaluate and improve the performance of protection systems during power swings short of hardware replacements. All options should be evaluated
Response: The issues related to power swings will be addressed in Phase III of this project according to the SAR, and the NERC System Protection and Control Subcommittee (SPCS) and Transmission Issues Subcommittee (TIS) are jointly developing a paper, *Issues Related to Protective System Response to Power Swings*.		
MRO's NERC Standards Review Subcommittee	Yes	On the topic of ‘adding in’ - listing and evaluating the transmission facilities below 200 kV, we propose the inclusion of qualifications that prevent the consideration and evaluation of irrelevant facilities (e.g. facilities that are not tripped by the applicable relay settings).
Response: The SDT believes the proposed criteria in Attachment B defining the test Planning Coordinators will use to determine which facilities must		

Organization	Yes or No	Question 10 Comment
comply with PRC-023 will address the commenters concerns.		
American Transmission Company	Yes	On the topic of 'adding in' - listing and evaluating the transmission facilities below 200 kV, we propose the inclusion of qualifications that prevent the consideration and evaluation of irrelevant facilities (e.g. facilities that are not tripped by the applicable relay settings).
Response: The SDT believes the proposed criteria in Attachment B defining the test Planning Coordinators will use to determine which facilities must comply with PRC-023 will address the commenters concerns.		
ERCOT ISO		ERCOT ISO thinks a standard drafting team can evaluate the Order 733 directives, work in conjunction with other Standard Drafting Teams already addressing some aspects of critical facilities, may be able to more succinctly arrive at an equally efficient and effective method of achieving the intent of the directive(s). The coordination between teams is vital to avoid confusion and possible overlap.
Response: The SDT has addressed the specific comment regarding coordination with the Reliability Coordination SDT (Project 2006-06) by modifying the standard to replace the phrase "critical to the reliability of the bulk electric system" with "that must comply with this standard." The SDT believes that the directed modifications to PRC-023-1 contained in Order No. 733 are unique to this standard and do not require coordination with other SDTs.		
E.ON U.S. LLC	Yes	
Wisconsin Electric		No comment

11. Do you agree with the scope of the proposed standards action?

Summary Consideration:

Several commenters indicated that they do not agree with the scope of the proposed standards action based on the technical comments submitted against many of the proposed actions submitted in response to the original FERC NOPR on PRC-023. In response, the SDT indicated that FERC considered the comments submitted to the original FERC NOPR on PRC-023 and issued directives in Order No. 733 that the SDT must address.

Several commenters indicated that the scope of the SAR should be modified to make clear that the drafting team may use equally effective alternatives to address the Commission's directives per the Commission in this order and other orders such as Order 693. In response the SDT cited the Standards Process Manual. The Standards Process Manual states that a Standard Authorization Request (SAR) is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified standards or the benefit of retiring one or more approved standards. This SAR is specific to addressing regulatory directives in Order No. 733. The SAR should only contain the scope and not include how the directives will be met as it is understood that the directives may be met in an equally effective alternative.

Many comments received indicated that the proposed modifications to PRC-023 reach beyond the directives without specifying which particular modifications are problematic. The SDT worked carefully to not go beyond the directives.

A commenter indicated that the scope should address apparent conflicts in timing of requirements posed by the standard. A newly proposed implementation plan will be proposed in the formal posting of PRC-023 that allows transition time for entities to become compliant with the modified requirements. The SDT agrees that a revised implementation plan is necessary and will post it for review by the industry during the next posting of the standard.

Some commenters suggested that several parts of the standard go too far (Appendix A R1.10) and will require documenting faults and clearing times to prove the fault duty of transformer connections. They also suggested the requirements to deal with out of step blocking relays should go in phase 3 and not in this standard. The SDT believes that evidence such as coordination curves or summaries of calculations are sufficient to demonstrate that relays set per criterion 10 do not expose the transformer to fault levels and durations beyond those indicated in the standard. The potential for out-of-step blocking protection elements to assert due to system load conditions already is addressed in PRC-023-1. Moving this subject from Attachment A to an explicit requirement in PRC-023-2 does not alter the requirement that already exists for Transmission Owners, Generator Owners, and Planning Coordinators. The SDT also notes that operation of out-of-step blocking elements due to system load conditions is outside the scope of Phase III of this project which is to address the directive regarding protection system operation during power swings.

Some commenters noted believe that removal of exclusion 3.1 in Att. A, will lead to reduced reliability because an operational decision to open breakers will be needed for loss of potential conditions. The SDT has modified section 1.6 in response to concerns that applying the standard to elements such as fault detectors that supervise directional distance elements could have a negative impact on reliability. The SDT has modified section 1.6 to include "Supervisory elements associated with current based communication assisted schemes where the scheme is capable of tripping for loss of communications." The SDT also modified the second bulleted item in section 2.1 (formerly 3.1) to add the clause, "except as noted in section 1.6 above."

Organization	Yes or No	Question 11 Comment
Pepco Holdings, Inc - Affiliates	No	We do not agree with the scope of the proposed standards action for numerous reasons. The documented responses to the original FERC NOPR on PRC-023 from numerous sources, including NERC and EEI, together make a rather convincing technical argument against many of these proposed actions. We support these technical arguments, which for the sake of brevity will not be repeated here. In addition, we have provided comments and objections on specific portions of the proposed standards action in our responses to questions 1 through 10 above.
Response: FERC considered the comments submitted to the original FERC NOPR on PRC-023 and issued directives in Order No. 733 that the SDT must address.		
MRO's NERC Standards Review Subcommittee	No	We agree that the topics of generator relay loadability and power swing protective relaying should be referred to in other separate standards. While we acknowledge that it is in everyone's best interest to respond to the FERC directives, there are numerous technical flaws that need to be resolved in their request. Forming a team and spending considerable resources will not gain industry acceptance to these directives.
Response: FERC considered the comments submitted to the original FERC NOPR on PRC-023 and issued directives in Order No. 733 that the SDT must address.		
American Transmission Company	No	We agree that the topics of generator relay loadability and power swing protective relaying should be referred to in other separate standards. While we acknowledge that it is in everyone's best interest to respond to the FERC directives, there are numerous technical flaws that need to be resolved in their request. Forming a team and spending considerable resources will not gain industry acceptance to these directives.
Response: FERC considered the comments submitted to the original FERC NOPR on PRC-023 and issued directives in Order No. 733 that the SDT must address.		
PacifiCorp	No	It is very difficult to comment on test parameters that have not been determined.
Response: The criteria that Planning Coordinators will use to determine which facilities must comply with PRC-023 were posted on September 23 for a		

Organization	Yes or No	Question 11 Comment
20-day informal comment period. The SDT has reviewed Requirement R5 and the criteria in Attachment B and has made conforming changes to ensure no conflicts exist. The full standard with Attachment B will be posted for a 45-day formal comment period.		
Kansas City Power & Light	No	Do not agree with all the proposals by the SDT as indicated by the comments regarding questions 1 through 8.
Response: Thank you for your comments. Please see the summary considerations above.		
ISO New England Inc.	No	We largely believe the scope will allow the drafting team to address the directives. However, we request that the scope be modified to make clear that the drafting may use equally effective alternatives to address the Commission's directives per the Commission in this order and other orders such as Order 693. **Response: The Standards Process Manual states that a Standard Authorization Request (SAR) is the form used to document the scope and reliability benefit of a proposed project for one or more new or modified standards or the benefit of retiring one or more approved standards. This SAR is specific to addressing regulatory directives in Order No. 733. The SAR should only contain the scope and not include how the directives will be met as it is understood that the directives may be met in an equally effective alternative.** The scope should address apparent conflicts in the timing of requirements posed by the standard. It is our understanding that, based on the final date afforded NERC to develop the criteria for the determination of sub-200 kV facilities,a newly proposed implementation plan will be offered to allow the Planning Coordinators an appropriate time frame to apply the criteria to determine the "critical" facilities below 200 kV. The implementation plan should cause the effective date for circuits described in 4.1.2 and 4.1.4 to be changed from "39 months following applicable regulatory approvals" to a date linked to the Planning Coordinators schedule to provide a list to its TOs, GOs and DPs. **Response: The SDT modified the implementation schedule for those requirements that the SDT has modified to address a FERC directive in Order No. 733. In addition, the SDT added a requirement, now Requirement R7, that requires the Transmission Owners, Generator Owners, and Distribution Providers to implement Requirement R1, Requirement R2, Requirement R3, and Requirement R4, and Requirement R5 for each facility that is added to the Planning Coordinator's list of facilities that must comply with this standard pursuant to Requirement R6, Part 6.12 by the later of the first day of the second calendar quarter after 24 months following notification by the Planning Coordinator of a facility's inclusion on such a list, or the first day of the first calendar quarter of the year in which criterion B6 first applies.**
Duke Energy	No	o The SAR states that Paragraph 162 is part of Phase I, but the new standard addressing stable power

Organization	Yes or No	Question 11 Comment
		swings is Phase III.
Response: The SAR shows the directive from P. 162 as part of Phase I to be implemented by March 18, 2011. However, this directive should be included in Phase III since it deals with the subject of relay operations due to power swings. The SDT reviewed the SAR and determined to leave this in Phase I because the directive says to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings but agrees that a new standard will be developed for this in Phase III of the project.		
ITC Holdings	No	Several parts of the standard go too far (Appendix A R1.10) and will require us to document faults and clearing times to prove the fault duty of transformer connections. Also the requirements to deal with out of step blocking relays should go in phase 3 and not in this standard.
Response: This is part of the existing, approved standard and the SDT cannot change this part of the standard since it is not associated with a directive in Order No. 733. The SDT removed out-of-step blocking from Requirement R1. The requirement pertaining to evaluation of out-of-step blocking protection has been moved to a separate requirement (now Requirement R2) to more clearly delineate this requirement from assessment of relay loadability of phase protective relays. Phase III of this project will address protective relays operating unnecessarily due to stable power swings and is not intended to address out of step blocking relays.		
	No	Removal of exclusion 3.1 in Att. A, will lead to reduced reliability because an operational decision to open breakers will be needed for loss of potential conditions. The corollary would be leaving the element in service with fast tripping enabled for a fault until the loss of potential condition can be diagnosed and corrected.
Response: The SDT has modified section 1.6 in response to concerns that applying the standard to elements such as fault detectors that supervise directional distance elements could have a negative impact on reliability. The SDT has modified section 1.6 to include "Supervisory elements associated with current based communication assisted schemes where the scheme is capable of tripping for loss of communications." The SDT also modified the second bulleted item in section 2.1 (formerly 3.1) to add the clause, "except as noted in section 1.6 above."		
E.ON U.S. LLC	No	
NPPD	No	
FirstEnergy	Yes	We agree that this standards action is necessary to meet the FERC directives, but have some concerns as we have stated in previous responses above.
Response: Thank you for your comments. Please see the summary considerations above.		

Organization	Yes or No	Question 11 Comment
TSGT System Planning Group	Yes	We agree that the scope meets the FERC directive, but some of the proposals in the proposed standard reach beyond the directive.
Response: Without additional details, the SDT cannot address the issues that the commenter has with the specific modifications to PRC-023-2 intended to address the FERC directives.		
Independent Electricity System Operator	Yes	We general agree with the proposed action but there are detailed changes that we have comments on, which are noted in our comments under Q1 to Q8
Response: Thank you for your comments. Please see the summary considerations above.		
ComEd	Yes	Yes, given that we assume that NERC must address all the FERC directives whether or not NERC or the industry agrees with them.
Response: FERC considered the comments submitted to the original FERC NOPR on PRC-023 and issued directives in Order No. 733 that the SDT must address.		
Long Island Power Authority	Yes	LIPA agrees with the scope in general. Please consider our comments above for answers to specific issues.
Response: Thank you for your comments. Please see the summary considerations above.		
Northeast Power Coordinating Council	Yes	
Bonneville Power Administration	Yes	
Dominion Electric Market Policy	Yes	
Arizona Public Service Company	Yes	
Southern Company	Yes	
NV Energy	Yes	

Organization	Yes or No	Question 11 Comment
Consumers Energy	Yes	
Idaho Power - System Protection	Yes	
Manitoba Hydro	Yes	
American Electric Power	Yes	
Wisconsin Electric		No comment

12. Are you aware of any regional variances that we should consider with this SAR?

Summary Consideration:

The majority of the commenters did not identify variances for consideration in the SAR. However, several commenters did point out that each Regional Entity has its own definition for BES and should be considered when addressing sub-100 kV facilities. In response, the SDT indicated that Attachment B to the standard will define criteria that Planning Coordinators must apply to determine if a facility must comply with the standard. In addition, FERC issued a BES NOPR on March 18, 2010 proposing a consistent approach to defining BES that (i) provides a 100 kV threshold for facilities that are included in the BES; and (ii) eliminates the currently-allowed discretion of a Regional Entity to define BES within its system without NERC or Commission oversight. In the NOPR, the Commission proposes that a Regional Entity must seek NERC and Commission approval before it exempts a transmission facility rated at 100 kV or above from compliance with mandatory Reliability Standards. In response to the NOPR, NERC submitted comments that supports the Commission's objectives of ensuring a common understanding and consistent application of the definition of BES across the regions. NERC also supports the Commission's objective that variations to application of the BES definition should be justified on the basis of reliability. To ensure these objectives are accomplished in a technically and legally appropriate manner, NERC proposed that the Commission should rely on the NERC Reliability Standards Development Process to consider, develop and implement new processes that may be needed, or to enhance existing processes. An Order on the matter has not been issued.

One commenter indicated concern that utilities with long lines and in weak areas will have difficulty protecting their lines and meeting the required loadability. Regions where there are very rural systems will want to write standards that allow adequate protection for their systems. Requirement R1 part 13 states that: "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." This was included in the standard for such cases where additional criteria are necessary.

Organization	Yes or No	Question 12 Comment
IRC Standards Review Committee	No	We are not aware of any regional variances per se. However, each regional entity has its own definition for BES and this needs to be considered when addressing sub-100 kV facilities.
Response: Attachment B to the standard will define criteria that Planning Coordinators must apply to determine if a facility must comply with the standard. In addition, FERC issued a BES NOPR on March 18, 2010 proposing a consistent approach to defining BES that (i) provides a 100 kV		

Organization	Yes or No	Question 12 Comment
threshold for facilities that are included in the BES; and (ii) eliminates the currently-allowed discretion of a Regional Entity to define BES within its system without NERC or Commission oversight. In the NOPR, the Commission proposes that a Regional Entity must seek NERC and Commission approval before it exempts a transmission facility rated at 100 kV or above from compliance with mandatory Reliability Standards. In response to the NOPR, NERC submitted comments that support the Commission's objectives of ensuring a common understanding and consistent application of the definition of BES across the regions. NERC also supports the Commission's objective that variations to application of the BES definition should be justified on the basis of reliability. To ensure these objectives are accomplished in a technically and legally appropriate manner, NERC proposed that the Commission should rely on the NERC Reliability Standards Development Process to consider, develop and implement new processes that may be needed, or to enhance existing processes. An Order on the matter has not been issued.		
ISO New England Inc.	No	We are not aware of any regional variances per se. However, each regional entity has its own definition for BES and this needs to be considered when addressing sub-100 kV facilities.
Response: Attachment B to the standard will define criteria that Planning Coordinators must apply to determine if a facility must comply with the standard. In addition, FERC issued a BES NOPR on March 18, 2010 proposing a consistent approach to defining BES that (i) provides a 100 kV threshold for facilities that are included in the BES; and (ii) eliminates the currently-allowed discretion of a Regional Entity to define BES within its system without NERC or Commission oversight. In the NOPR, the Commission proposes that a Regional Entity must seek NERC and Commission approval before it exempts a transmission facility rated at 100 kV or above from compliance with mandatory Reliability Standards. In response to the NOPR, NERC submitted comments that support the Commission's objectives of ensuring a common understanding and consistent application of the definition of BES across the regions. NERC also supports the Commission's objective that variations to application of the BES definition should be justified on the basis of reliability. To ensure these objectives are accomplished in a technically and legally appropriate manner, NERC proposed that the Commission should rely on the NERC Reliability Standards Development Process to consider, develop and implement new processes that may be needed, or to enhance existing processes. An Order on the matter has not been issued.		
Long Island Power Authority	Yes	NPCC BPS definition based on A10 criteria is a regional variance.
Response: Attachment B to the standard will define criteria that Planning Coordinators must apply to determine if a facility must comply with the standard. In addition, FERC issued a BES NOPR on March 18, 2010 proposing a consistent approach to defining BES that (i) provides a 100 kV threshold for facilities that are included in the BES; and (ii) eliminates the currently-allowed discretion of a Regional Entity to define BES within its system without NERC or Commission oversight. In the NOPR, the Commission proposes that a Regional Entity must seek NERC and Commission approval before it exempts a transmission facility rated at 100 kV or above from compliance with mandatory Reliability Standards. In response to the NOPR, NERC submitted comments that support the Commission's objectives of ensuring a common understanding and consistent application of the definition of BES across the regions. NERC also supports the Commission's objective that variations to application of the BES definition should be justified on the basis of reliability. To ensure these objectives are accomplished in a technically and legally appropriate manner, NERC proposed that the Commission should rely on the NERC Reliability Standards Development Process to consider, develop and implement new processes that may be needed, or to enhance existing processes. An Order on the matter has not been issued.		

Organization	Yes or No	Question 12 Comment
ITC Holdings		Utilities with long lines and in weak areas will have difficulty protecting their lines and meeting the required loadability. Regions where there are very rural systems will want to write standards that allow adequate protection for their systems.
Response: Requirement R1 part 13 states that: "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." This was included in the standard for such cases where additional criteria are necessary.		
Northeast Power Coordinating Council	No	
Pepco Holdings, Inc - Affiliates	No	
PSEG Companies	No	
Bonneville Power Administration	No	
FirstEnergy	No	
MRO's NERC Standards Review Subcommittee	No	
Dominion Electric Market Policy	No	
E.ON U.S. LLC	No	
Arizona Public Service Company	No	
American Transmission Company	No	
PacifiCorp	No	
Southern Company	No	

Organization	Yes or No	Question 12 Comment
TSGT System Planning Group	No	
NV Energy	No	
NPPD	No	
Consumers Energy	No	
Idaho Power - System Protection	No	
Kansas City Power & Light	No	
Independent Electricity System Operator	No	
ComEd	No	
Manitoba Hydro	No	
Wisconsin Electric	No	
Ameren	No	
American Electric Power	No	
	No	
Duke Energy	No	

13. **Are you aware of any associated business practices that we should consider with this SAR?**

Summary Consideration:

Commenters did not indicate that there are any business practices that the team should consider with the SAR.

One commenter suggested that R2 should be modified to read "The Each Transmission Owner, Generator Owner, or and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, Settings1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall forward this information to the Planning Coordinator, Transmission Operator, and Reliability Coordinator. The burden for acknowledging agreement or specifying reasons for disagreement should reside with the Planning Coordinator, Transmission Operator, and Reliability Coordinator. The commenter suggested that the SDT develop additional requirements similar to those in FAC-008 @ R2 and R3. This proposal is outside the scope of the SAR that is intended to limit the project to addressing the directives in Order No. 733. This suggestion could be made when the standard is reviewed during the required 5-year review of the standard.

Organization	Yes or No	Question 13 Comment
Northeast Power Coordinating Council	No	
Pepco Holdings, Inc - Affiliates	No	
PSEG Companies	No	
Bonneville Power Administration	No	
FirstEnergy	No	
IRC Standards Review Committee	No	
MRO's NERC Standards Review	No	

Organization	Yes or No	Question 13 Comment
Subcommittee		
E.ON U.S. LLC	No	
Arizona Public Service Company	No	
American Transmission Company	No	
PacifiCorp	No	
Southern Company	No	
TSGT System Planning Group	No	
Consumers Energy	No	
Idaho Power - System Protection	No	
Kansas City Power & Light	No	
Independent Electricity System Operator	No	
ComEd	No	
Manitoba Hydro	No	
Wisconsin Electric	No	
ISO New England Inc.	No	
Long Island Power Authority	No	

Organization	Yes or No	Question 13 Comment
Ameren	No	
American Electric Power	No	
ITC Holdings	No	
	No	
Duke Energy	No	
NPPD	Yes	See Question 7.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form for Relay Loadability Order (No. 733) (Project 2010-13)

Please **DO NOT** use this form. Please use the electronic form located at the link below to submit **INFORMAL** comments on the proposed **applicability test contained in Attachment B** to PRC-023-2. The electronic comment form must be completed **by October 12, 2010**.

If you have questions please contact Stephanie Monzon at Stephanie.monzon@nerc.net or by telephone at 610-608-8084.

Background Information

NERC Standard PRC-023-1 – Transmission Relay Loadability was approved by FERC as mandatory and enforceable in March 2010, with direction that NERC make a number of changes.

The Standard Drafting Team made changes to PRC-023-1 to address the several directives from Order 733 and posted the proposed changes for comment from August 19, 2010 – September 19, 2010. The proposed changes did NOT include Attachment B to the standard as it was at the time still a work in progress. Attachment B is intended to contain the test that the Planning Coordinators must use to determine whether a sub-200kV facility is critical to the reliability of the Bulk-Power System. The inclusion of a test is a directive in Order No. 733:

- p. 69 . . . modify Requirement R3 of the Reliability Standard to specify the test that planning coordinators must use to determine whether a sub-200 kV facility is critical to the reliability of the Bulk-Power System.

Requirement R5 (previously R3) of PRC-023-2 states:

R5. Each Planning Coordinator shall apply the criteria in Attachment B to determine which of the facilities (transmission lines operated below 200 kV and transformers with low voltage terminals connected below 200 kV) in its Planning Coordinator Area are critical to the reliability of the BES to identify the facilities below 200 kV that must meet Requirement R1 to prevent cascading when protective relay settings limit transmission loadability. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

5.1 The Planning Coordinator shall have a process to use the criteria established within Attachment B to determine the facilities that are critical to the reliability of the Bulk Electric System.

5.2 Each Planning Coordinator shall maintain a current list of facilities determined according to the process described in Requirement R5 Part 5.1.

5.3 Each Planning Coordinator shall provide a list of facilities to its Regional Entity, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to that list.

Applicability Testing Criteria

NERC Reliability Standard PRC-023 — Transmission Loading Availability was developed in answer to relay loadability problems highlighted during the blackout of 2003. Relay loadability has been either causal or contributory to a majority of major system disturbances dating back to the 1965 blackout and beyond. The proposed Standard is intended to prevent circuits when thermally overloaded from prematurely tripping due to relay loadability. The concept is to allow some time for system operators to intervene and alleviate the overloads.

If any circuit trips under adverse conditions, even if the loss of that circuit does not itself cause a cascade, the resultant weakened transmission system leaves the bulk electric system more exposed to possible cascading outages. Therefore, applicability of PRC-023 should not only be for operationally significant circuits that could cause a cascade, but also for circuits that are prone to overloads (relievable through operator action) during contingencies.

Planning coordinators test for conformance with the TPL standards through various contingency analyses that should prevent critical circuits from becoming overloaded. The TPL criteria contingencies studied normally screen for susceptibility to cascading and system instability. However, overloading of circuits for short periods of time is permissible, and assumes operator action can alleviate such overloads in a timely fashion. Although the planning tests are fairly rigorous they are usually limited to N-1 or N-2 level contingencies. However, it is for the unforeseen combinations of outages that we want assurance that circuits would not trip for relay loadability reasons.

The recommendations stemming from the 2003 blackout called for review of circuits 200 kV and above. Logically, all circuits, including those below 200 kV, that are operationally significant to the reliability of the bulk electric system (BES) should be tested for susceptibility.

System studies go to great lengths to determine transfer capabilities on critical transmission interfaces. Planning and operational studies are routinely conducted to determine the transfer capabilities of circuits such as those that are part of interconnection reliability operating limits (IROLs), flowgates in the Eastern Interconnection, Commercially Significant Constraints in the Texas Interconnection, or Rated Paths in the Western Interconnection. Any circuit that is important enough to reliability to be actively managed to prevent overloads should also be important enough to prevent it from inadvertently tripping due to relay loadability for combinations of outages that are not normally tested.

Similarly, any circuit that is operationally significant to nuclear plant off-site power design criteria for maintaining voltage, regardless of its operating voltage, should also be protected from inadvertently tripping due to relay loadability for combinations of outages that are not normally tested.

The relay loadability screening described below offers another layer of defense-in-depth.

Note: These criteria define the family of circuits that would have their protection system reviewed for conformance to the PRC-023 loadability criteria. If the protection system passes, no further action is necessary. If it fails, then the condition would have to be mitigated.

Strategy of Testing

The tests for the applicability of PRC-023 should leverage as much existing work as possible, including existing system analyses routinely performed by the planning coordinators, transmission planners, and transmission operators, and minimize the creation of additional analytical workload.

Mitigation Timeframes

If the protection systems of a circuit are tested and found out of conformance with PRC-023 loadability criteria, the protection systems must be mitigated. After the initial application of these criteria, which will be governed by the standard implementation plan, the following time frames for mitigation should be used:

- If found in the planning analyses: circuits should be mitigated within 24 months or by the time the overload problem would be expected.
- If found in the normally performed seasonal operational planning analyses: loadability concerns should be mitigated before the operating time being analyzed. If not possible to mitigate prior to the operating time being studied, operators should be made aware of the loadability limitation and operate the system accordingly.

To expedite the project to address the directives from FERC Order No. 733, the Standard Drafting Team is posting Attachment B to PRC-023-2 for an abbreviated 20-day informal comment period.

Please note that the posting of Attachment B to PRC-023-2 is an **INFORMAL** posting.

1. Attachment B is intended to contain the test that the Planning Coordinators must use to determine whether a sub-200kV facility is critical to the reliability of the bulk power system. Do you agree that the method proposed in Attachment B is a technically sound approach to determine whether a sub-200kV facility is critical to the reliability of the bulk power system?

   ☐ Yes

   ☐ No

   Comments:

PRC-023 – Attachment B

Criteria

Review each circuit (line and transformer) less than 200 kV needs against the following criteria to determine if that circuit needs to be evaluated for conformance with PRC-023. If any of the criteria apply to a circuit, the circuit needs to be evaluated.

1. Each circuit that is a monitored element of a flowgate in the Eastern Interconnection, Commercially Significant Constraint[1] in the Texas Interconnection, or rated path in the Western Interconnection.
2. Each circuit that is a monitored element of an IROL.
3. Each circuit that are directly related to off-site power supply to nuclear plants.
4. Each circuit whose outage causes unacceptable voltages (pursuant to plant license design specifications) on the off-site power bus at a nuclear plant, regardless of its proximity to the plant.
5. Each circuit agreed to by the Reliability Coordinator, the Planning Coordinator, and Regional Entity.

   Note – This criterion allows the Reliability Coordinator, Planning Coordinator and Regional Entity additional latitude in designating other circuits that should be tested for conformance to the relay loadability criteria.

6. Each circuit operated between 100 kV and 200 kV that exceeds its Short Term Emergency Rating by 15 percent or more as a result of a double contingency (for those combinations selected by engineering judgment in TPL-003 System Performance Following Loss of Two or More BES Elements analyses) beyond the requirements of the TPL-003 standard, i.e., loss of a single circuit, followed by loss of a second circuit, without system adjustments in between.

   Note – This Modified TPL C3 contingency reflects a situation where a System Operator may not have time between two contingencies to make appropriate system adjustments.

[1] In the ERCOT Zonal Protocols (effective through November 30, 2010):

Commercially Significant Constraint (CSC): A constraint in the ERCOT Transmission Grid that is found, through the process described in Section 7, to result in Congestion which limits the free flow of energy within the ERCOT market to a commercially significant degree. The reference to Section 7 is to the ERCOT Zonal Protocols.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Abbreviated Informal Comment Period Open
September 23 - October 12, 2010

Now available at: http://www.nerc.com/filez/standards/SAR_Project%202010-13_Order%20733%20Relay%20Modifiations.html

Project 2010-13: Relay Loadability Order

A draft PRC-023 Attachment B has been posted for a 20-day informal comment period through **8 p.m. Eastern on October 12, 2010**.

PRC-023 – Attachment B provides a set of criteria for the Planning Coordinator to use in determining which of the facilities (transmission lines operated below 200 kV and transformers with low voltage terminals connected below 200 kV) in its Planning Coordinator Area are critical to the reliability of the bulk electric system to identify the facilities below 200 kV that must meet specific relay loadability criteria. The criteria proposed in Attachment B were under field test and not available to the drafting team when the team prepared the other modifications to PRC-023-1 that were posted through September 19, 2010.

The Standards Committee authorized an abbreviated comment period for this posting to assist the team in meeting its project schedule. Order 733 directed that the initial set of specific changes to PRC-023-1, including the criteria addressed in Attachment B, be filed with the Commission by March 18, 2011.

Informal 20-day Comment Period Open through October 12, 2010

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at Monica.Benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page:
http://www.nerc.com/filez/standards/SAR_Project%202010-13_Order%20733%20Relay%20Modifiations.html

Transition from Reliability Standards Development Procedure Version 7 to Standard Processes Manual

In accordance with the Standard Processes Manual approved by FERC on September 3, 2010, the drafting team is using an "informal" comment period to solicit stakeholder feedback. The new standard development process allows drafting teams to use informal comment periods. Unlike formal comment periods where a drafting team provides a response to each comment submitted, with informal comment periods the drafting team provides a summary response to each question asked on its comment form, but the team is not obligated to provide an individual response to each comment submitted. The summary response will indicate whether stakeholders support the proposal and will identify any additional changes made based on stakeholder comments. With informal comment periods drafting teams are not required to provide an individual response to each comment submitted. This change to the process is intended to give drafting teams more time to deliberate on technical issues, as opposed to deliberating on individual responses to comments. Note that while informal comment periods are allowed in the new standard process for preliminary drafts of proposed standards, formal comment periods are still required for the final draft of each standard.

Next Steps

The drafting team will post its response to comments received during this period. The drafting team will use specific feedback from this informal posting to develop a final draft of Attachment B for inclusion in the next posting of PRC-023-2.

Project Background

When FERC issued Order 733, approving PRC-023-1 — Transmission Relay Loadability, it directed several changes to that standard and also directed development of one or more new standards within specified time periods. NERC filed for clarification and rehearing asking for clarity and an extension of time to address the directives, however without a response to the requests for clarification and rehearing, NERC must adhere to the deadlines established in Order 733.

The SAR for Project 2010-13 – Relay Loadability Order subdivides the standard development related directives into three phases. Phase I addresses the specific directives from Order 733 that identified required modifications to various elements within PRC-023-1. Phase II addresses directives associated with development of a new standard to address generator relay loadabilty. Phase III addresses directives associated with writing requirements to address protective relay operations due to power swings.

Applicability of Proposed PRC-023-2

Distribution Providers that own specific facilities (see standard for details)
Generator Owners that own specific facilities (see standard for details)
Planning Coordinators
Transmission Owners that own specific facilities (see standard for details)

Standards 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 Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060

Individual or group. (39 Responses)
Name (22 Responses)
Organization (22 Responses)
Group Name (17 Responses)
Lead Contact (17 Responses)
Question 1 (39 Responses)
Question 1 Comments (39 Responses)

-
Individual
Donna Jordan
California ISO
No
Further clarifications to the criteria in Attachment B are required.
Individual
Robin W. Blanton
Piedmont EMC
Yes
I would like to have a provision in the Standard so that all radial transmission lines are excluded from this requirement since they are not used for load transfer. Otherwise, a lot of utilities will have to comply wiht this Standard by stating that we do not have any critical lines and have a letter from the TO stating that we don't have any critical lines.
Individual
Michael Gammon
Kansas City Power & Light
No
Do not agree with the approach in R5 and R5.1 in proposed Standard PRC-023-2 to dictate to the Planning Coordinator additional criteria beyond the TPL Standards to identify operating sensitivities. The proposed Appendix B proposes to establish additional considerations of facilities by which the Planning Coordinator must determine if those facilities are critical to the reliability of the BES. There are a variety of differing, and often complex, operating conditions that dictate the need for transmission facilities. The TPL standards require extensive studies of the transmission system be performed under steady state and dynamic conditions to understand and identify sensitive areas of the transmission system and enable Reliability Coordinators to identify flowgates and other operating sensitivities in their respective regions. In light of the Reliability Coordinators awareness of transmission sensitivities through these studies, it seems unnecessary to dictate to the Reliability Coordinators additional criteria as proposed here in this Appendix B.
Individual
Jonathan Appelbaum
United Illuminating
Yes
We agree with the approach. We are concerned that the periodicity of the determination of the lines between 100 kV and 200 kV is not specified in Attachment B number 6 or R5. Is this an annual determination or performed only when a study for the Planning Horizon is completed. Is the study period the short term planning horizon (1-5 year) or long-term planning horizon (6-10 year)? For a temporary maintenance condition, e.g. a line is removed from service for 14 months, is the PC required to reevaluate the list of facilities?
Individual
Ted Risher
Ingleside Cogeneration, LP
No
In paragraph 97 of Order 733, FERC allows for entities to challenge the identification of sub-200 kV transmission facilities as critical to the BES. The paragraph reads as follows: “Finally, commenters argue that there should be some mechanism for entities to challenge criticality determinations. We agree that such a mechanism is appropriate and direct the ERO to develop an appeals process (or point to a process in its existing procedures) and submit it to the Commission no later than one year after the date of this Final Rule.” Most of the proposed criteria leverage well-understood concepts such as violations of IROLs or double contingencies. However, the proposed attachment includes a catchall statement under Criterion #5 that the RC, PC, and RE can designate circuits as critical without any defined basis. This makes an appeals process imperative since there are economic impacts to facility owners of such designations. This process needs to be proposed and evaluated by the industry concurrently with Appendix B, not at a future date.
Group
Northeast Power Coordinating Council
Guy Zito
No
Support conformance with PRC-003 for all circuits 100 kV and above and as long as a reasonable period of time is allowed for proper implementation. However, some circuits could be prioritized based on their criticality to the system. The methodology in Attachment B should be considered as determining those circuits which should be prioritized first, followed by the remaining circuits 100 kV and above. Further clarification is needed for Criterion #2 because the circuits which

make up an IROL can change depending upon the state of the system, while evaluation of relay loadability must be done in advance. The following language is proposed: “Each circuit that is a monitored element of an IROL, assuming that all transmission elements are in service and the system is under normal conditions.” Criterion #3 is unclear. The term “directly related to” (off-site power supply to nuclear plants”) is so broad that it essentially covers all transmission circuits that are connected to a nuclear plant. If this criterion meant to be the circuits that are directly connected to a nuclear plant, and which form a critical path to supply backup power to the plant, then the criterion should be clarified. For example, some plants may have low voltage (4160 V) cross-connects or distribution voltage (13.8 kV) circuits that provide off-site or qualified alternate AC power supplies to nuclear plants which are likely not going to be subject to relay loadability concerns due to transmission events (or such circuits may simply be providing power to office buildings). As written, it could be interpreted that such circuits may have to be considered as part of this requirement. This is unnecessary. This criterion needs to be revised such that lower voltage circuits which cannot be subjected to relay loadability concerns are explicitly excluded, and also to limit its applicability to circuits that provide critical off-site power to nuclear plants as identified in the Nuclear Plant Interface Requirements (NPIRs) provided by the Nuclear Plant Generator Operators to the applicable Transmission Entities in accordance with NUC-001-2. Criterion #4 does not belong in this standard, and should be eliminated. If the outage of an element causes unacceptable voltages elsewhere, appropriate actions should be taken to address and remediate this issue. Conformance with PRC-023 is not going to solve the undesired consequences of an outage, which could occur any time. NUC-001-2 already requires that the Nuclear Plant Generator Operator and the applicable Transmission Entities: • coordinate on the testing, calibration and maintenance of on-site and off-site power supply systems and related components (R9.3.3) • incorporate the NPIRs into their planning analyses of the electric system (R3) • incorporate the NPIRs into their operating analyses of the electric system (R4.1) • operate the electric system to meet the NPIRs (R4.2). Criterion #6 should be deleted. The PC and TP assess their future systems according to the performance requirements stipulated in the TPL standards, including those in TPL-003. To require an entity to assess the impact of a contingency that is not required by TPL-003 would go beyond the basic planning and design requirements. Further, it raises the question on why do we single out the 100-200 kV facilities, but not all 200kV and above facilities? Requirement R1 in the recent draft PRC-023 already asks for setting transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating. This requirement is applicable for conditions with and without faults on the system, and is sufficient to cover the testing condition stipulated in the proposed Criterion #6. The system is neither planned nor operated to allow for two overlapping outages without operator action in between. If this criterion is retained, it should be made consistent with the requirements of TPL-003, where operator actions can be assumed between the first and second contingencies.
Group
PacifiCorp
Sandra Shaffer
Yes
Group
Pacific Northwest Small Public Power Utility Comment Group
Steve Alexanderson
No
The comment group agrees with all the criteria but number 6. Consider a local loop above 100 kV that is fed from a single radial tap from the BES. Some regions continue to treat such radially fed systems as BES due to the presence of normally open tie switches on the distribution system. It is conceivable that a multiple contingency within the loop could cause one or more of the remaining un-faulted lines within the loop to overload to beyond 115% of their short term ratings. While undesirable, such a scenario does not rise to the level of a BES event. Even if the lines cannot overload, entities will be required to run simulations to prove non-applicability where such systems should be excluded by simple inspection. The comment group suggests that radially operated (operated is the key word here) systems be excluded.
Individual
Kathleen Goodman
ISO New England Inc.
No
General comment: ISO New England supports conformance with PRC-003 for all circuits 100 kV and above allowing for a reasonable period of time for proper implementation. However, some circuits could be prioritized based on their criticality to the system. The methodology in Attachment B should be considered as determining those circuits which should be prioritized first, followed by the remaining circuits 100 kV and above. Comments regarding specific criteria: 2. Further clarification is needed regarding criterion #2, since the circuits which make up an IROL can change depending upon the state of the system while evaluation of relay loadability must be done in advance. We proposed the following language: “Each circuit that is a monitored element of an IROL, assuming that all transmission elements are in service and the system is under normal conditions.” 3. The breadth of criterion #3 is unclear and may, as written, be broader than necessary or appropriate. For example, some plants may have low voltage (4160 V) cross-connects or distribution voltage (13.8 kV) circuits that provide off-site or qualified alternate AC power supplies to nuclear plants which are likely not going to be subject to relay loadability concerns due to transmission events (or such circuits may simply be providing power to office buildings). As written, it could be interpreted that such circuits may have to be considered as part of this requirement, and we believe this to be unnecessary. This criterion needs to be modified such that lower voltage circuits which cannot be subjected to relay loadability concerns are explicitly excluded and also to limit its applicability to circuits that provide critical off-site power to nuclear plants, as identified in the Nuclear Plant Interface Requirements (NPIRs) provided by the Nuclear Plant Generator Operators to the applicable Transmission Entities in accordance with NUC-001-2. 4. Criterion #4 should be eliminated. NUC-001-2 already requires that the Nuclear Plant Generator Operator and the applicable Transmission Entities: • coordinate on the testing, calibration and maintenance of on-site and off-site power supply systems and related components (R9.3.3) • incorporate the NPIRs into their planning analyses of the electric system (R3) • incorporate the NPIRs into their operating analyses of the electric system (R4.1) • operate the electric

system to meet the NPIRs (R4.2). 6. Criterion #6 is overly stringent and should be deleted. The system is neither planned nor operated to allow for two overlapping outages without operator action in between. If this criterion is retained, it should be made consistent with the requirements of TPL-003, where operator actions can be assumed between the first and second contingencies.
Group
MRO's NERC Standards Review Subcommittee
Carol Gerou
No
In general, Midwest Reliability Organization's NERC Standards Review Subcommittee (NSRS) agrees with the proposed criteria. However, there should be further clarification and qualification of the criteria noted below. In the introduction, the wording of "determine if that circuit needs to be evaluated for conformance with PRC-023" does not clearly tie to Requirement R5.1 or use the same language. We suggest revised wording to more clearly refer to Requirement R5.1 by using the more similar language of, "determine the circuits that are critical to the reliability of the BES". For Criteria #4, add the qualification that the outage condition is assessed for the near term planning horizon (years 1 to 5), rather imply that the criteria includes consideration of the less certain longer term planning horizon (years 6 to 10). We suggest adding the words, "for the near term planning horizon", to the end of criteria #4. For Criteria #6, clearly limit the types of double contingencies that should be considered to those identified in TPL-003 (e.g. more severe Category B), rather than imply any and all double contingencies beyond TPL-003. In addition, there is no bound on all the N-1-1 contingencies that must be considered (in TPL-003, the planner is allow to at least restrict the scope of study to the more severe contingencies. We suggest revising the wording to, ". . . as a result of double contingencies that are required in the TPL-003 standard and in addition, the more severe contingencies of loss of a single circuit, followed by the loss of a second circuit, without system adjustments in between". We do not believe that a flowgate should be automatically included in the criteria. The NERC Glossary of Terms definition of flowgate would require every flowgate in the IDC to be identified. This is a problem because flowgates are included in the IDC for many reasons not just because reliability issues are identified. Flowgates could be included to simply study the impact of schedules on a particular interface as an example. It does not mean the interface is critical. Furthermore, the list of flowgates in the IDC is dynamic. The master list of IDC flowgates is updated monthly and IDC users can add temporary flowgates at anytime. Criterion 1 would imply that any monitored facility then becomes subject to the standard. Furthermore, IDC is more of a congestion management tool than a reliability tool. FERC recognized this in Order 693, when they directed NERC to make clear in IRO-006 that the IDC should not be relied upon to relieve IROLs that have been violated. Rather, other actions such as redispatch must be used in conjunction. Thus, it would appear that inclusion of a flowgate in the IDC does not indicate that it is critical. For Criteria #5, we suggest that the applicable entities be changed. The Transmission Planner should be added because they have local planning responsibilities and knowledge that should be factored into the consideration of critical circuit classification. We suggest that the Regional Entity be removed because it does not fall within the Reliability Assurer functional tasks.
Group
Arizona Public Service Company
Jana Van Ness, Director Regulatory Compliance
Yes
Individual
Kasia Mihalchuk
Manitoba Hydro
No
1) For criteria #5, Regional Entity does not need to be involved in determining the operational significant circuits. It should be changed to: "Each circuit determined and agreed to by the Reliability Coordinator and the Planning Coordinator." 2) For criteria #6, it should be clarified that it would be up to the Planning Coordinator to make the engineering judgment in determining the double contingencies beyond the requirements of TPL-003 standard. In addition, there should be some coordination between the methodology for critical asset determination in the cyber security standards and the relay loadability standard so multiple assessments are not required by the Planning Coordinator. Ideally, the scope of the TPL assessment should provide sufficient information for the other relevant NERC standards.
Group
East Kentucky Power Cooperative, Inc.
Rick Drury
No
East Kentucky Power Cooperative (EKPC) agrees in principle with the establishment of criteria to be used to identify circuits to be evaluated for conformance with PRC-023-2. However, EKPC does not believe that all of the proposed criteria are appropriate. For instance, the first listed criterion that specifies any circuit listed as the monitored element of a flowgate appears to be excessive. EKPC does not believe that flowgates necessarily correspond with a critical facility requiring further analysis of relay settings. EKPC also does not agree with the 6th listed criterion as stated. We propose that the criterion be modified to allow system adjustments between contingencies in accordance with the TPL-003 standard. EKPC feels that this criterion stated in Attachment B should maintain consistency with the requirements for system performance stated in TPL-003. With the elimination of the first criterion listed in Attachment B and the modification of the 6th listed criterion to allow system adjustments between contingencies, EKPC would support the method listed in Attachment B for identification of critical circuits.
Individual
Bill Miller
ComEd

Yes
Criteria number 6 calls for a test that includes comparison to the “Short Term Emergency Rating”. We have had some confusion on exactly which rating this refers to. Thus, our comment is to add some clarifications to this term. For example if this is the rating that is closest to a 15 minute highest seasonal facility rating, state this directly or in a footnote.
Group
Southern Company
Andy Tillery
Yes
For clarity, it is suggested that the two sentences above the criteria list of Attachment B be revised as follows: Review each (line and transformer) circuit less than 200 kV against the following criteria to determine if that circuit must conform with PRC-023. If any of the criteria below apply to the circuit under review, the circuit must conform to the requirements of PRC-023.
Group
SERC Planning Standards Subcommittee
Philip R. Kleckey
No
Although this question states Attachment B contains the critical facilities test, it instead appears to contain a listing of facilities to evaluate to determine if they are critical, and not the test itself. Attachment B states that if any of the criteria apply to a circuit, the circuit needs to be evaluated. It should state that the circuit should be considered critical. Item1 should be removed since not all flowgates are related to reliability. The remaining items adequately cover lines less than 200 kV that are critical to reliability. Item 3 contains a typo. Change "are" to "is." Item 3: The word "related" is too vague, recommend to use the word "connected" instead. Item 6 is confusing and should be revised as follows: "Each circuit operated between 100 kV and 200 kV that exceeds its Short Term Emergency Rating by 15 percent or more as a result of double contingency combinations selected by engineering judgment in TPL-003 Category C3, but without system adjustments in between." The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Group
Pepco Holdings, Inc. - Affiliates
Richard Kafka
No
Mitigation timeframes are identified on the unofficial comment form, which differ from those defined by the implementation plan in the most recent draft version of the standard. To be enforceable all mitigation timeframes need to be identified in the standard itself. Secondly, the mitigation timeframes in the comment form use phrases like “by the time the overload problem would be expected” and “before the operating time being analyzed”. The timeframe requirements for mitigation need to be better defined to be auditable. The Planning Coordinator needs to determine an “exact date” when the mitigation is required prior to the overload taking place. If that date is more than 24 months away then the protection system owner will have to mitigate the facility before the required date established by the Planning Coordinator. However, if the projected overload date is less than 24 months away, the protection system owner will have 24 months after being notified by the Planning Coordinator to mitigate the facility; and operators shall be made aware of the loadability limitation and should operate the facility accordingly until the facility is mitigated. The issue is that it may take 24 months for the protection system owner to make necessary hardware upgrades to mitigate the loadability limitation.
Individual
Terry Harbour
MidAmerican Energy
No
The proposed criteria is not technically sound as many of the criteria are completely arbitrary and have no technical basis. The appropriate basis for a critical element is something that could result in instability, uncontrolled separation, or cascading which is the basis for all NERC standards, the 2003 blackout, and the Energy Policy Act wording. The following proposed criteria is not technically sound and should be deleted: 1. Being a flowgate or monitored element of a flowgate. The loss of a flowgate that doesn’t result in the instability, uncontrolled separation or cascading, may pose no more jeopardy to grid reliability than any other element that isn’t designated as a flowgate. This was proved by FERC’s own TIER report. 2. A circuit agreed to by the RC, PC, and RE. This has absolutely no technical basis whatever and is completely arbitrary. This requirement also completely excludes the actual owner / operator of the facilities. 3. A circuit that exceeds 15% of its short-term emergency rating as a result of a double contingency. This criteria exceeds what is required in the TPL standards. For category C3 contingencies, the Planning Coordinator is allowed to assume operator intervention between the first and second independent contingency. Further, this even exceeds what FERC ordered in their directive in paragraph 79 from Order 733 which states: “To achieve this goal, the test to determine which sub-200 kV facilities are subject to PRC-023-1 must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning.” This proposed criterion is not consistent with the TPL standards but rather exceeds those standards. This completely ignores any unusual or temporary operating conditions that could result from ice storms or even maintenance practices.
Individual
Jerry Tang
MEAG Power
Yes

A minor clarification is needed. The first line under Criteria reads,"Review each circuit (line and transformer) less than 200 kV needs ..." It needs to be reworded as follows: "Review each circuit (line and low-side transformer) between 100 kV and 200 kV needs ..." The first line of number 6 needs to be reworded by deleting "between 100 kV and 200 kV." It would now read, " EAch circuit operated that exceeds its Short Term ..."
Individual
JC Culberson
EROCT
No
In response to Attachment B of PRC-023, ERCOT ISO respectfully submits the following comments: Criterion 1 – the phrase “Commercially Significant Constraint in the Texas Interconnection” and the associated footnote should be removed. Commercially Significant Constraints (CSCs) are market-driven constraints designed to economically manage congestion under the ERCOT Zonal market construct. CSCs are not reliability constraints that reflect the criticality of an element relative to system reliability. Furthermore, as noted in footnote 1 in Attachment B, the ERCOT market is transitioning from the current Zonal construct to a Nodal construct on December 1, 2010. Under the Nodal design CSCs will not exist. Accordingly, the rules that apply to CSCs will expire prior to the implementation of this rule. Criterion 3 – The word “are” should be replaced with the word “is”. Criterion 4 – There should not be any circuits whose outage causes unacceptable voltages on the off-site power bus at a nuclear plant. Therefore, this criterion should be removed. Criterion 6 - Short Term Emergency Rating is not a defined term. Accordingly, it is not clear what rating is at issue. Emergency Rating is a defined term, and ERCOT assumes that is the rating envisioned by this criticality identifier. If that is the case, it needs to be clarified. If some other rating is envisioned, that too needs to be clarified, because, as noted, Short Term Emergency Rating is not defined.
Group
System Protection Department
Bill Middaugh
No
1. We think that criterion 1 should be changed as follows “... Texas Interconnection, or path in the Western Interconnection that is listed as an Existing Path in the current year WECC Path Rating Catalog.” The current wording “rated path in the Western Interconnection” is too general and could be interpreted to mean any element in the Western Interconnection that has a thermal rating. 2. Change “are” in criterion 3 to “is.” 3. We think that criterion 5 is too vague, may be discriminatory, is unnecessary, and should be removed. There is no basis listed for determining circuits in this criterion, the criterion may be applied discriminatorily or differently even within the same interconnection, it potentially excludes the protection system owner from having input in the process, and there is no redress for appeal by the owner. Protection system owners do not want transmission elements to be removed from service due to loading and nothing precludes a protection system owner from applying PRC-023 requirements to lower voltage lines. We also think that getting agreement between the three required entities could be troublesome. If some form of criterion 5 is included in the Attachment B, then it needs to define a technical basis for the request for inclusion, a procedure to initiate the request for inclusion, due process defined for evaluation of the request, and inclusion of the protection system owner in the evaluation process and the agreement. It seems that criterion 6 defeats the need for criterion 5. 4. We think that criterion 6 should be revised to read as “Each transmission line operated between 100 kV and 200 kV that exceeds its highest seasonal 15-minute Facility Rating or each transformer operated between 100 kV and 200 kV that exceeds its operator established emergency transformer rating as a result of a double contingency…” The current wording would have no positive impact on BES reliability. First, the existing term “Short Term Emergency Rating” is not defined and is not used in PRC-023. We are suggesting changing the concept to terms that are used in the standard. Secondly, nothing in PRC-023 requires the protection system owner to set the relays to operate at more than 115% of an emergency rating or a short term (15-minute) rating. An element loading that qualifies under the drafting team's proposed criterion 6 would not have to be considered unless it exceeded the 115% of the emergency or short term rating, which the protection system settings would not be required to permit per the requirements of PRC-023. That is why we changed the criterion to indicate inclusion of the element for any loading that exceeded the emergency or short term rating for the contingencies studied.
Individual
Thad Ness
American Electric Power
No
These AEP comments are provided in the context of the primary goal of this standard as specified under R5, "... to prevent cascading ...". The fundamental concern behind these comments is that the implemented methodology should not unnecessarily and erroneously classify facilities as “critical”, even for the limited purposes of this single standard. Such labels should only be applied to facilities that are truly “critical” to the reliability of the Bulk Electric System, and thus, the implemented methodology should only identify “critical” facilities. In addition, the implementation plan must allow for ample time to mitigate the initial wave of “critical” facilities that would reasonably be expected to be significantly larger than the incremental number of new “critical” facilities that will be identified on a routine basis going forward. Specific comments on the posted criteria being proposed by NERC are outline below. (1) Flowgates in the Eastern Interconnection (and Commercially Significant Constraints in the Texas Interconnection) are defined for various reasons and not just for reliability purposes. Flowgates are defined for interface monitoring, congestion management, and other purposes unrelated to reliability. Many of the flowgates reflect nominal normal and emergency ratings to limit loadings on these facilities below their thermal capabilities, and not for the purpose of preventing cascading. As such, being part of a flowgate definition alone should not be the basis for suspecting susceptibility to cascading, and thus, not a good reason for having such facilities meet the requirements of this standard. Furthermore, flowgates are updated on a continuous, and many times, temporary basis, and thus, not a practical basis for identifying facilities for the purposes of this standard. Therefore, this criterion should not be used as a basis for defining “critical” facilities for the purposes of this standard. (2) Since the identification of “critical” facilities is made by the Planning Coordinators in the planning horizon (to give the relay owners ample time to address compliance with the requirements of this standard), then the IROL methodology that is

applicable to the planning horizon (as specified under FAC-010) must be used to identify such “critical” facilities. In the case of PJM, IROL facilities in the planning horizon are those SOL facilities that have been identified as potentially resulting in cascading outages. As such, system reinforcements are developed in the planning horizon to ensure that such cascading conditions are mitigated and do not materialize in the eventual operating horizon. Consequently, PJM does not define any IROL facilities in the planning horizon. Therefore, this criterion can not be used as a basis for defining “critical” facilities in the planning horizon for the purposes of this standard. On the other hand, IROL facilities identified in the operating horizon (as specified under FAC-011), would be appropriate to use to identify “critical” facilities for the purposes of this standard. (3) On the surface, this appears to be a reasonable criterion. However, need to clarify what is meant by “directly related”. If these are facilities that are identified under the NPIRs mandated under NUC-001, then their associated relay loadability performance should be addressed under NUC-001. Moving this requirement from PRC-023 to NUC-001 will ensure that all requirements associated with nuclear plants are addressed together under the same standard (NUC-001). (4) On the surface, this appears to be a reasonable criterion. However, when such voltage studies are conducted and unacceptable voltage conditions are identified in the planning horizon, system reinforcements and other mitigating actions are taken to ensure that such conditions do not occur in the operating horizon. Consequently, since no such conditions will be allowed to remain, then no “critical” facilities should result from this criterion. On that basis, this criterion should be eliminated. If the criterion is kept, then it should be moved under NUC-001 for the same reasons noted under criterion 3. Also, the criterion needs to specify the starting point of the outage analysis that identifies the unacceptable voltages. Furthermore, the outaged facility needs to be subject to heavy loadings to be considered for possible designation as a “critical” facility. The outage of the facility for reasons unrelated to heavy loadings should not be a basis for making that facility subject to the requirements of this standard. (5) This criterion is too open ended and should be eliminated. As the auditing entity, the Reliability Entity should not be providing any input outside of the auditing process. The Planning Coordinator has the flexibility to engage any other entities as it sees fit, and thus, there is no need to single out the Reliability Coordinator under this criterion. Also, even if these entities were kept and others, such as the Transmission Owners, were added, what would be the basis that these entities would use to identify these “critical” facilities? Again, this criterion is too open ended, it does not add anything meaningful to the effort, and thus, it should be eliminated. (6) On the surface, this appears to be a rational basis for identifying “critical” facilities since it utilizes cascading simulations. However, it stops short of performing the N-1-1-1 simulations (declares all overloaded facilities after the N-1-1 simulations as “critical” rather than going the extra step of performing the N-1-1-1 simulations to determine if any additional facilities become overloaded) that are needed to demonstrate susceptibility to cascading. Furthermore, an additional filter, one that takes into consideration the amount of load that would be placed at risk by the N-1-1-1 cascading scenario, also needs to be incorporated into this methodology. This can best be achieved by giving the TOs an opportunity to review the preliminary results from their Planning Coordinator and to demonstrate to their Planning Coordinator as to the amount of load that would be at risk through the cascading of the proposed “critical” facilities. If the TOs can successfully demonstrate to their Planning Coordinator that for certain facilities the amount of load that would be at-risk (from the cascading scenario) falls below a specified threshold level (to be determined by their Planning Coordinator), then those facilities would be excluded from the final list of “critical” facilities. In the end, this should be the only criterion that is used to identify “critical” facilities for the purposes of this standard. Regarding the use of Short Term Emergency Ratings in the simulations, it should be noted that most ratings used in planning base cases (the ones that would be used by the Planning Coordinator) are Long Term Emergency Ratings, and thus, converting such models to reflect Short Term Emergency Ratings just for the purposes of conducting these simulations would not be practical. Therefore, the specification should be made as a higher percentage of Long Term Emergency Ratings.
Group
FirstEnergy
Sam Ciccone
No
FirstEnergy has the following comments related to the proposed criterion presented in the Attachment B of PRC-023-2. A. Consistency with the CIP-002-4 bright-line criteria. When comparing the proposed PRC-023-2 Attachment B criterion to the bright-line criteria proposed for CIP-002-4 Attachment 1 Critical Asset determination there is a great deal of overlap in concepts presented for transmission facilities. For example, each cover aspects of transmission facilities associated with IROLs and transmission facilities that are operationally significant for the safe operation and shutdown of a nuclear generation plant. Since these are parallel standard development efforts we suggest to the extent possible the PRC team and CIP team use consistent language when equivalent technical concepts are utilized for critical facility determinations. FirstEnergy's suggested changes identified below for the six individual criterion are consistent with CIP-002-4 Attachment 1 proposals made by FirstEnergy. B. Leverage existing studies and analysis - planning timeframe. We concur with the drafting team’s perspective that tests for the applicability of PRC-023 should leverage as much existing work as possible, however, FE believes any study/analysis work should be limited to that performed by the planning coordinators and transmission planners and not the transmission operators as suggested by the comment form background information. FE believes the appropriate timeframe to identify the sub 200kV critical facilities is the planning horizon based on forward looking studies conducted by or under the supervision of the planning coordinator. This is consistent with PRC-023-1 (R3) and the proposed PRC-023-2 (R5) since the planning coordinator is the applicable entity required to determine the sub 200kV critical facilities and the time-horizon for the requirement is long-term planning. Information based on analysis performed by the reliability coordinator or transmission operator within the operating time horizon, such IROL, can be temporary, dynamic and subject to change. Therefore, it should be clear that the intent of facilities associated with IROLs are based on planning timeframe analysis. See FE's proposed changes to the second criterion. C. Mitigation Timeframes. The comment form provided by the drafting team presented two criteria for mitigation timeframe. This information should not be buried in a comment form but rather part or the standard's Effective Date's section (Section 5) and presented in an Implementation Plan so that it may be fully vetted by industry through the standards development process. The mitigation timeframe should be clear that the minimum expectation is 24-months upon the asset owner being notified by the planning coordinator of a new critical facility determination. The first bulleted item presented by the team is vague if its meant to be the "greater of" or "lesser of" 24 months or the time the overload problem would be expected. As stated above, FE believes that critical facility determinations are appropriately based on planning horizon timeframes and therefore it should be clear that an asset owner is afforded a minimum 24-month period to mitigate any critical facility required to meet PRC-

023. This is consistent with the approved version 1 and the proposed version 2 standard. D. Specific comments on the Attachment B Criterion. i. Criteria 1: A flowgate should not be automatically included in the criteria. The NERC Glossary of Terms definition of flowgate would require every flowgate in the IDC to be identified. This is a problem because flowgates are included in the IDC for many reasons not just because reliability issues are identified. Flowgates are used for market recognition to study the impact of schedules on a particular interface and may not present a reliability concern. The team should consider a more limiting use of flowgate or striking the criteria. ii. Criteria 2: FE agrees with the concept of associating a critical facility with IROL however we believe two important revisions are required. First, the critical facility should be based on the contingent facilities that describe the IROL and not the monitored elements. Second, the IROL determinations should be based on planning horizon studies. FirstEnergy proposes the following text for criteria 2: "Transmission Facilities that the Planning Coordinator or Transmission Planner designates that, if destroyed, degraded, misused or otherwise rendered unavailable, demonstrates the need for an Interconnection Reliability Operating Limit (IROL)." iii. Criteria 3: FE supports criteria 3 and proposes revision so that criteria 3 reads “BES Facilities providing offsite power requirements as identified in the Nuclear Plant Interface Requirements.” iv. Criteria 4: Criteria 4 should be removed since criteria 3, as revised above, should adequately cover the transmission facilities deemed critical for a nuclear generation facility as designated in their NPIRs. v. Criteria 5: Criteria 5 is vague, open ended and should be removed. Any criteria that the PC may use to include other facilities should be explicitly stated in Attachment B. The RC should be removed since it makes evaluations within the operating horizon timeframe which is not appropriate for requirement R5. vi. Criteria 6: FE supports this criteria.
Group
Salt River Project
Cynthia Oder
No
There is an error in the wording under R5, this requirement states "transmission lines operated at below 200kV and transformers below 230kV." It should state "transmission lines operated between 100kV and 200kV and transformers operated between 100kV and 200kV" otherwise this standard will fall out of the definition of BES.
Individual
Randi Woodward
Minnesota Power
No
Minnesota Power recommends that the Standards Drafting Team consider changing item #6 to read as follows: Each circuit operated between 100 kV and 200 kV that exceeds its Short Term Emergency Rating by 15 percent or more as a result of a double contingency (for those combinations selected by engineering judgment in TPL-003 System Performance Following Loss of Two or More BES Elements analyses).
Group
Operational Compliance
Cathy Koch
Yes
We would like to propose a rewrite for criterion #6. The proposed rewrite is: "Each circuit operated between 100 kV and 200 kV that exceeds its short term Emergency Rating by 15% or more as the result of a double contingency, beyond the requirements of TPL-003 C3 (i.e. loss of a single circuit followed by the loss of a second circuit without manual system adjustments in between), for all combinations selected by engineering judgment in the TPL-003 C3 analyses." Note - This modified TPL-003 C3 contingency reflects a situation where a System Operator may not have time between two contingencies to make appropriate system adjustments. The term “Short Term Emergency Rating” is not a defined term so “short term” should not be capitalized and could potentially be removed. The definition of Emergency Rating specifies a finite time period. The addition of the word 'manual' before 'system adjustment' mirrors the TPL-003 C3 definition and better clarifies what is meant by 'system adjustment' as this is not a defined term. This would then imply that automatic system adjustments that occur due to RAS and SPS operations, transformer tap changes and automatic switching of reactive resources would not constitute a 'system adjustment' in the context of this criterion (further supported by the note to criterion #6).
Individual
Dan Rochester
Independent Electricity System Operator
No
We agree with Criteria # 1, 2 and 5, but do not agree with Criteria #3, #4 and #6. Criterion #3 is unclear. The term “directly related to” (off-site power supply to nuclear plants” is so broad that it essentially covers all transmission circuits that are connected to a nuclear plant. If this criterion meant to be the circuits that are directly connected to a nuclear plant and which form a critical path for supply backup power to the plant, then the criterion should say so to provide better clarity. Criterion #4 does not belong in this standard. If the outage of an element causes unacceptable voltages elsewhere, appropriate actions should be taken to address and remediate this issue. Conformance with PRC-023 is not going to solve the undesired consequences of an outage, which could occur any time. Criterion #6 is troublesome and perhaps not needed. The PC and TP assess their future systems according to the performance requirements stipulated in the TPL standards, including those in TPL-003. To require an entity to assess the impact of a contingency that is not required by TPL-003 would go beyond the basic planning and design requirements. Further, it raises the question on why do we single out the 100-200 kV facilities, but not all 200kV and above facilities? Requirement R1 in the recent draft PRC-023 already asks for setting transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating. This requirement is applicable for conditions with and without faults on the system, and is sufficient to cover the testing condition stipulated in the proposed Criterion #6. We suggest to remove this Criterion #6.
Individual

Kirit Shah
Ameren
No
Criterion #1 : A monitored flowgate does not imply a reliability issue. Flowgates are monitored for many reasons, some for reliability and some to regulate the amount of firm transmission service. In non-FTR markets, firm transmission monitoring may be a partial function of reliability. However, in FTR markets, the sale of firm transmission service may be related to the acquisition of ARR/FTRs. Under these scenarios, the flowgate may be in place to ensure FTR funding sufficiency. Circuits with high degrees of uncertain loading are most susceptible but the mere presence of uncertainty does not make them critical for the reliability of the BES. Criterion #2: We are ok with the element related to “IROL” type criterion including outage of such element causing instability or cascading effect on the BES. Criterion #3: We believe that our comment should be restated as “This criterion should not be included in a relay loadability test. The fact that a circuit supplies a reserve aux transformer at a nuclear plant does not make the circuit critical to the transmission network or to the plant. If the outage of a circuit results in the outage or instability of a nuclear plant, then these issues should have been addressed in the design of the plant supply and/or in the TPL-002 assessment.” Criterion 4: This issue should be covered in TPL-002 or NUC-001. This item should not be included in a relay loadability test. Criterion #5: This is an open-ended criterion without any supporting basis. It is also unclear who at the Regional Entity would “sign-off”, Compliance, Engineering, or someone else? Further, this type of criterion would introduce more inconsistencies rather uniformity. If such a criterion is used, we suggest that the RC, PC, and/or RE should work closely with the local Transmission Planners to determine if a circuit should be assessed for criticality and further subjected to the relay loadability test. Criterion #6: Short Term Emergency Rating, although capitalized in here, is not a NERC defined term. Further, the criterion does not identify the time duration that the STE rating would be applicable, nor the basis for such a rating. If a common time duration and basis for rating could be established, a common loading above the STE rating could be established. A loading of 120% may be more indicative of a cascade than 115%, and would be applicable for fast acting contingencies involving multiple circuits, including Category C1 bus faults, C2 breaker failures, or C5 double-circuit tower outages. We do not agree with the proposal that system adjustments would not be allowed for slower multiple contingency Category C3 events (sometimes referred to as N-1-1 outages) involving lines, generators or transformers, as this requirements clearly steps on standard TPL-003.
Group
Midwest ISO Standards Collaborators
Jason L. Marshall
No
We have many concerns with the approach identified. We do not believe that a flowgate should be automatically included in the criteria. The NERC Glossary of Terms definition of flowgate would require every flowgate in the IDC to be identified. This is a problem because flowgates are included in the IDC for many reasons not just because reliability issues are identified. Flowgates could be included to simply study the impact of schedules on a particular interface as an example. It does not mean the interface is critical. Furthermore, the list of flowgates in the IDC is dynamic. The master list of IDC flowgates is updated monthly and IDC users can add temporary flowgates at anytime. Criterion 1 would imply that any monitored facility then becomes subject to the standard. Furthermore, the IDC is more of a congestion management tool than a reliability tool. FERC recognized this in Order 693, when they directed NERC to make clear in IRO-006 that the IDC should not be relied upon to relieve IROLs that have been violated. Rather, other actions such as redispatch must be used in conjunction. Thus, it would appear that inclusion of a flowgate in the IDC does not indicate that it is critical. For criterion 2, we believe any contingent facility or prior outage that sets up the IROL should be included if criterion 6 is revised to allow operator intervention between contingencies. If criterion 6 is not revised, we do not support adding contingency or prior outages. For criterion 3, what does it mean to be directly related to the off-site supply to nuclear plants? Does this means it is identified in the NPIRs associated with the agreements mandated by NUC-001-2? This criteria needs to be further refined if retained. For criterion 4, since NERC standards collectively require us to operate the system to N-1 and to plan the system with Category C contingencies, this criterion should never identify any facilities with low voltage. For criterion 5, this criterion is too open ended and should be eliminated. Since the Regional Entity is the auditor, they should not provide direct input into what is included. This seems like carte blanche for the Regional Entity to add to the list of facilities whenever the latest issue arises. Could we end up having a situation where after every event analysis the Regional Entity identifies even more facilities? If the Regional Entities have needs to identify facilities they should do this by providing input through the standards development process to suggest modifications to the criteria. Will the RC and PC be judged similar to how entities are currently being judged regarding the number of Critical Assets that have been identified for CIP? If so, this could become a “bring me a rock” exercise. If the PC and RC don’t identify enough facilities, will the ERO and Regional Entities pressure them to identify more? Industry will be better served if we eliminate this open ended criteria and just identify bright line criteria for what should be included. This really seems like a catch all in case we forget to add all the necessary criteria. For criterion 6, we disagree with this criterion because it exceeds what is required in the TPL standards. For category C3 contingencies, the Planning Coordinator is allowed to assume operator intervention between the first and second independent contingency. Further, this even exceeds what FERC ordered in their directive in paragraph 79 from Order 733 which states: “To achieve this goal, the test to determine which sub-200 kV facilities are subject to PRC-023-1 must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning.” This proposed criterion is not consistent with the TPL standards but rather exceeds those standards.
Individual
Steve Rueckert
WECC
No
The approach described is reasonable, however, it would be more comprehensive and consistent to replace in item 1 (Attachment B), "rated path in the Western Interconnection" with "paths included in Table of Major WECC Transfer Paths in the Bulk Electric System". This Table is more comprehensive because it is identified by the WECC Operating

Committee and is consistent with the major paths used in other WECC Standards. Item 5 appears vague. What does “agreed to by the Reliability Coordinator, the Planning Coordinator, and Regional Entity mean?” Do all three need to be in agreement before a facility is to be added to the list to be evaluated, or can any one of them add it to the list? How are these entities supposed to come to agreement and document that agreement. If there is not a proactive effort to develop the list and “agree” to it, there probably won’t be a list. I’m not sure I understand Item 6. Does this mean that results of TPL-003 assessments will helpt identify circuits that have to be evaluated? TPL-003 is eventually going to go away when the ATFNSDT effort is completed. The requirement to conduct the types of assessments currently included in TPL-003 will not go away, but the specific referenct to TPL-003 could become obsolete.
Individual
Chifong Thomas
Pacific Gas and Electric Company
No
We believe the approach described is reasonable, however, as written Item 1 (Attachment B) concerning WECC paths is vague. We suggest, replacing "rated path in the Western Interconnection" with "paths included in Table of Major WECC Transfer Paths in the Bulk Electric System". We believe referencing this Table would provide clarity because the paths in this Table are identified by the Operating Committee in WECC and are consistent with the major paths used in other WECC Standards, such as FAC-501-WECC-1, PRC-004-WECC-1, and TOP-007-WECC-1.
Group
Dominion
Louis Slade, Jr.
No
While items 1-5 seem reasonable, Dominion takes exception with item six (6). Item six goes beyond TPL-003 criteria, by assuming the operator will have no time between contingency events to make system adjustments. TPL-003 was thoroughly vetted when it was developed and is sound criteria that has been in place for years. Circuits below 200 kV are less critical to the security of the bulk electric system. We see no reason why the standard should not allow that the operator will make system adjustments between the first and second contingency.
Individual
Stephen R. Stafford
Georgia Transmission Corporation
No
Criterion 6 of Attachment B states "Each circuit operated between 100 kV and 200 kV that exceeds its Short Term Emergency Rating by 15 percent or more as a result of a double contingency..." The basis for the 15 percent criterion has not been clearly explained. What is the basis for this criterion? Based on this criterion, multiple lines could be identified as critical facilities, when, in fact, loss of these lines could have no significant impact to the BES(i.e. not cause cascading outages on the BES).
Individual
Greg Rowland
Duke Energy
No
• General Comment – It should be made clear that the application of these criteria is intended to determine which facilities must be evaluated for applicability of PRC-023-2 and may not necessarily dictate modification of relay settings. Situations where there is time for operator intervention, or no cascading, wouldn’t need loadability protection. • Criteria 1 – We do not believe that flowgates should be automatically included as a criteria, since a flowgate may be in the IDC for business reasons. Also, the list of flowgates is dynamic. • Criteria 2 – Monitored elements of an IROL are also dynamic and we question how you could apply this in the planning timeframe so it could be used to set relays. IROLs identified in the planning horizon should be mitigated by some action prior to reaching the operating horizon. This criteria is not specific enough to be applied consistently. • Criteria 3 – What is meant by “directly related”? There is a difference between normal off-site power and emergency power. We don’t think the NPIRs would clarify this situation. Is the expectation that no lines connected to a nuclear plant trip except for a fault on the line? • Criteria 4 – If we had such a circuit it would violate TPL-002 as well as the NPIRs, so this is not a useful criteria, because you’ll never identify anything with it. • Criteria 5 – It doesn’t make sense to include the Regional Entity, because the Regional Entity doesn’t do the analysis. Also, this criteria just says you can go beyond the existing criteria, which is always an option – so why include it as a criteria? • Criteria 6 – “Short Term Emergency Rating” is not a defined term. However its use in conjunction with the 15% overload suggests that a 15-minute Emergency Rating is what is intended. Some Transmission Owners haven’t determined sufficiently short term Emergency Ratings to meet the intent of this criteria, and if they set their relays at 115% of their shortest term Emergency Rating they would restrict loadability more than the standard should allow. Regardless of how the criteria for contingency line loading are defined in Attachment B, the criteria should match the requirements of PRC-023-2.
Individual
Armin Klusman
CenterPoint Energy
No
Considering situations where the transmission system may be at risk of cascading outages or voltage collapse, CenterPoint Energy believes sub-200 kV elements should be considered operationally significant only whenever reasonably contemplated scenarios would cause high amperage and low voltage to be experienced on the elements. Criteria 6 that proposes loading greater than 15% of the short term emergency rating following a double contingency is not a technically sound method to indicate if an element is operationally significant. CenterPoint Energy recommends only criteria 1 through 5 be used to determine whether a sub-200 kV element is operationally significant to the reliability of the

bulk power system.
Group
Bonneville Power Administration
Denise Koehn
No
BPA would like to raise the concern regarding the terminology being used in PRC-023. An underlying principle of the standard is to "Determine which of the facilities in its Planning Coordinator Area are critical to the reliability of the BES…". BPA would like to take this opportunity to point out that determination of “critical” as PRC-023 is applied may not be directly reflective of CIP Critical Asset identification. BPA feels this is appropriate due to the guidance provided in CIP-002 R1 where the Risk-Based Assessment Methodology should include the following considerations (as we used to develop BPA's methodology): 1) Control centers and backup control centers; 2) Transmission substations that support the reliable operation of the Bulk Electric System; 3) Generation resources that support the reliable operation of the Bulk Electric System; 4) Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration; 5) Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more; 6) Special Protection Systems that support the reliable operation of the Bulk Electric System; and 7) Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment. No minimum kV levels are instructed to be specifically used to identify CIP Critical Assets where PRC-023 is heavily driven by kV levels. BPA believes it would be very labor intensive to try and come up with which circuits would exceed the STE rating by 15% or more. BPA would like to understand the benefit of this study to increasing reliability. For Attachment B, BPA believes the performance requirement needs to be clarified further. The term "double contingency" and reference to "TPL-003" needs to be more specific, since TPL does cover more than just N-2 contingency of circuit elements. Additionally, regarding the Standard itself, for some local areas, if three lines are feeding the local area and it has been planned per the Standards (e.g. one single 115 kV line can't feed 100% of load in the area for loss of the other two), it seems like if two of the lines are lost simultaneously, then loss of the third line quickly, rather than waiting for an operator response may be preferable. This could be a safety issue and the operator may have no control over outcome. Additional comments: BPA would find it helpful if the drafting team were to create a cross-walk of the FERC directives (as listed on Page 3 and 4 of the SAR) and how/where the drafting team is addressing them.
Individual
Charles Lawrence
American Transmission Company
No
In general, we agree with the proposed criteria. However, we propose the following changes to the introduction, Criteria #4 and Criteria #6. [[1]]- In the introduction, the wording of “determine if that circuit needs to be evaluated for conformance with PRC-023” does not clearly refer to Requirement R5.1 or use the same language as R5.1. We believe that the wording in Attachment B should match the wording in R5.1. However, use of the terminology, “critical to reliability of the BES”, keeps causing confusion with the meaning of the concept of “critical” as it is defined in the CIP-002 standard. Therefore, we propose replacing the “critical” terminology in R5.1 with distinctly different terminology like, “that have major operational significance to the reliability of the BES”. Then, use wording similar to R5.1 in Attachment B such as, “determine the circuits that have major operational significance to the reliability of the BES”. [[2]]- For Criteria #4, add the qualification that the outage condition is assessed for the near term planning horizon (years 1 to 5), rather imply that the criteria includes consideration of the less certain longer term planning horizon (years 6 to 10). We suggest adding the words, “for the near term planning horizon”, to the end of criteria #4. [[3]]- For Criteria #6, clearly limit the types of double contingencies that should be considered to those identified in TPL-003 (e.g. more severe Category B), rather than imply any and all double contingencies beyond TPL-003. In addition, there is no bound on all the N-1-1 contingencies that must be considered (in TPL-003, the planner is allow to at least restrict the scope of study to the more severe contingencies. We suggest revising the wording to, “. . . as a result of double contingencies that are required in the TPL-003 standard and in addition, the more severe contingencies of loss of a single circuit, followed by the loss of a second circuit, without system adjustments in between”.
Individual
Alice Murdock Ireland
Xcel Energy
No
Item 1 – it is not clear how ‘temporary flowgates’ would be considered I this application; “commercial” considerations should not be part of a reliability standard; “rated path” in WECC is not clear – are these any path in the WECC Path Catalog, or is it intended to mean the “Major WECC Paths…”? Item 4 - we feel it should be eliminated from the list of criteria. Since NERC standards collectively require us to operate the system to N-1 and to plan the system with Category C contingencies, this criterion should never identify any facilities with low voltage. Item 5 – this appears to give carte blanche authority to the PC/RC/RE to decide a circuit is subject to evaluation; we believe this should be tempered with concurrence from the TO/GO/DP.
Group
IRC Standards Review Committee
Ben Li
No
Criterion 1 is inappropriate and should be eliminated. It states that any monitored facility below 200KV would be subject to this standard. A facility that is designated as a flowgate should NOT be automatically assumed to have an impact on reliability. Flowgates are included in the IDC for many reasons and not always because the facilities are critical to bulk system reliability. Some flowgates are defined and included in the IDC only to have the PTDF, OTDF and LODF

calculated. In general, flowgates are not a good indicator for reliability needs; the master list of IDC flowgates is updated monthly and IDC users can add temporary flowgates at anytime. Furthermore, IDC is primarily used to study congestion and is the basis of Transmission Loading Relief (TLR) which is not a reliability tool. FERC recognized this in Order 693, when they directed NERC to make clear in IRO-006 that the IDC should NOT be relied upon to relieve IROLs that have been violated and other actions such as redispatch must be used in conjunction with TLR. Criterion 2 should state that any contingent facility or prior outage that sets up the IROL be included, except where such facility is used as a proxy for assessing the IROL. Criterion 3 is unclear and should be clarified. What does it mean to be "directly related" to the off-site supply to nuclear plants? More clarity in the wording is needed. Is the intent that facilities that provide off-site power to nuclear plants as defined in the NPIRs associated with the agreements mandated by NUC-001-2 are captured in this standard? Criterion 4 is not needed since NERC standards already contain requirements to operate the system to N-1 and to plan the system with Category C contingencies. Therefore, this criterion would never identify any facilities whose outage would cause low voltage. Criterion 5 is too open ended and should be eliminated. The Regional Entity serves primarily as the compliance enforcement authority and not the technical assessor of what facilities are critical for bulk power reliability. They do not perform any of the operating and planning functions required to comply with reliability standards. These criteria should strive to be as close as possible to "bright line" tests. Criterion 5 is in a sense rhetorical, like defining a word with the same word. Criterion #6 should be deleted. This criterion does not recognize that the system is neither planned nor operated to allow for two overlapping outages without operator action in between. This goes beyond the assessment and performance requirements of TPL-003, where operator actions can be assumed between the first and second contingencies. We also ask why a 15% over Short Term Emergency Rating is an appropriate level, there is no justification.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Relay Loadability Order — Project 2010-13

The Relay Loadability Order Drafting Team thanks all commenters who submitted comments on the proposed applicability test contained in Attachment B to PRC-023-2. These standards were posted for a 20-day abbreviated public comment period from September 23, 2010 through October 12, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 39 sets of comments, including comments from more than 117 different people from approximately 95 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

http://www.nerc.com/filez/standards/SAR_Project%202010-13_Order%20733%20Relay%20Modifiations.html

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, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Index to Questions, Comments, and Responses

The Industry Segments are:

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7 — Large Electricity End Users
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9 — Federal, State, Provincial Regulatory or other Government Entities
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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.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity 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.	Dean Ellis	Dynegy Generation	NPCC	5
8.	Brian Evans-Mongeon	Utility Services	NPCC	8
9.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
10.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	Chantel Haswell	FPL Group, Inc.	NPCC	5
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1

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

14.	Michael R. Lombardi	Northeast Utilities	NPCC	1
15.	Randy MacDonald	New Brunswick System Operator	NPCC	2
16.	Bruce Metruck	New York Power Authority	NPCC	6
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	Saurabh Saksena	National Grid	NPCC	1
21.	Michael Schiavone	National Grid	NPCC	1
22.	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
2.	Group	Steve Alexanderson	Pacific Northwest Small Public Power Utility Comment Group			X	X						

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ronald Sporseen	Blachly-Lane Electric Cooperative		3
2.	Ronald Sporseen	Central Electric Cooperative		3
3.	Ronald Sporseen	Consumers Power		3
4.	Ronald Sporseen	Clearwater Power Company		3
5.	Ronald Sporseen	Douglas Electric Cooperative		3
6.	Ronald Sporseen	Fall River Rural Electric Cooperative		3
7.	Ronald Sporseen	Northern Lights		3
8.	Ronald Sporseen	Lane Electric Cooperative		3
9.	Ronald Sporseen	Lincoln Electric Cooperative		3
10.	Ronald Sporseen	Raft River Rural Electric Cooperative		3
11.	Ronald Sporseen	Lost River Electric Cooperative		3
12.	Ronald Sporseen	Salmon River Electric Cooperative		3
13.	Ronald Sporseen	Umatilla Electric Cooperative		3
14.	Ronald Sporseen	Coos-Curry Electric Cooperative		3
15.	Ronald Sporseen	West Oregon Electric Cooperative		3
16.	Ronald Sporseen	Pacific Northwest Generating Cooperative		5

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

17.	Ronald Sporseen	Power Resources Cooperative	3
18.	Russell A. Noble	Cowlitz County PUD No. 1	3, 4, 5
19.	Dave Proebstel	Clallam County PUD	3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X

Additional Member	Additional Organization	Region	Segment Selection	
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	WPS Corporation	MRO	3, 4, 5, 6
4.	Jason Marshall	Midwest ISO Inc.	MRO	2
5.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
6.	Ken Goldsmith	Alliant Energy	MRO	4
7.	Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6
8.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
9.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
10.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
11.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
12.	Scott Nickels	Rochester Public Utilties	MRO	4
13.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Philip R. Kleckey	SERC Planning Standards Subcommittee	X		X		X					

Additional Member	Additional Organization	Region	Segment Selection	
1.	John Sullivan	Ameren Services Company	SERC	1
2.	Charles Long	Entergy	SERC	1
3.	James Manning	North Carolina Electric Membership Corporation	SERC	3
4.	Jim Kelley	PowerSouth Energy Cooperative	SERC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

5.	Bob Jones	Southern Company Services, Inc. - Trans.	SERC	1
6.	Pat Huntley	SERC Reliability Corporation	SERC	10

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Richard Kafka	Pepco Holdings, Inc. - Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alvin Depew	Potomac Electric Power Company	RFC	1
2.	Walt Blackwell	Potomac Electric Power Company	RFC	1
3.	Carl Kinsley	Delmarva Power & Light Co.	RFC	1
4.	Jason Parsick	Potomac Electric Power Company	RFC	1
5.	Evan Sage	Potomac Electric Power Company	RFC	1
6.	Rob Wharton	Atlantic City Electric	RFC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Bill Middaugh	System Protection Department	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Pearsall	Tri-State Generation and Transmission Ass'n., Inc.	WECC	1, 3, 5
2.	Gary Preslan	Tri-State Generation and Transmission Ass'n., Inc.	WECC	1, 3, 5
3.	Matthew Leyba	Tri-State Generation and Transmission Ass'n., Inc.	WECC	1, 3, 5
4.	LeRoy Martinez	Tri-State Generation and Transmission Ass'n., Inc.	WECC	1, 3, 5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Rich Maxwell	FE	RFC	
2.	Doug Hohlbaugh	FE	RFC	
3.	Jeff Mackauer	FE	RFC	

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Jason L. Marshall	Midwest ISO Standards Collaborators		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joe O'Brien	NIPSCO	RFC	1
2.	Terry Harbour	MidAmerican	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

3.	Jim Cyrulewski	JDRJC Associates, LLC	RFC	8
4.	Barb Kedrowski	We Energies	RFC	3, 4, 5
5.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
6.	Joe Knight	Great River Energy	MRO	1, 3, 5, 6
7.	Kirit Shah	Ameren	SERC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Louis Slade, Jr.	Dominion	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection	
1.	Mike Garton	Electric Mkt. Policy	RFC	5, 6
2.	Michael Gildea	Electric Mkt. Policy	MRO	5, 6
3.	Angela Park	Electric Tranmission	SERC	1, 3
4.	John Loftis	Electric Tranmission	SERC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection	
1.	Lorissa Jones	BPA, Transmission Reliability Program	WECC	1
2.	Dick Winters	BPA, Transmission Substation Operations	WECC	1
3.	Curt Wilkins	BPA, Transmission Control Cntr HW Design & Maint	WECC	1
4.	Steve Larson	BPA Legal	WECC	1
5.	Rita Coppernoll	BPA, Transmission SPC Technical Svcs	WECC	1
6.	Dean Bender	BPA, Transmission SPC Technical Svcs	WECC	1
7.	Chuck Matthews	BPA, Transmission Planning	WECC	1
8.	Berhanu Tesema	BPA, Transmission Planning	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
12.	Individual	Jana Van Ness	Arizona Public Service Company	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
13.	Individual	Rick Drury	East Kentucky Power Cooperative, Inc.	X		X		X					
14.	Individual	Andy Tillery	Southern Company	X		X							
15.	Individual	Cynthia Oder	Salt River Project	X		X		X	X				
16.	Individual	Cathy Koch	Operational Compliance	X		X		X					
17.	Individual	Donna Jordan	California ISO		X								
18.	Individual	Robin W. Blanton	Piedmont EMC			X							
19.	Individual	Michael Gammon	Kansas City Power & Light	X		X		X	X				
20.	Individual	Jonathan Appelbaum	United Illuminating	X									
21.	Individual	Ted Risher	Ingleside Cogeneration, LP					X					
22.	Individual	Kathleen Goodman	ISO New England Inc.		X								
23.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
24.	Individual	Bill Miller	ComEd	X		X							
25.	Individual	Terry Harbour	MidAmerican Energy	X									
26.	Individual	Jerry Tang	MEAG Power	X		X		X					
27.	Individual	JC Culberson	EROCT		X								
28.	Individual	Thad Ness	American Electric Power	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
29.	Individual	Randi Woodward	Minnesota Power	X		X		X	X				
30.	Individual	Dan Rochester	Independent Electricity System Operator		X								
31.	Individual	Kirit Shah	Ameren	X		X		X	X				
32.	Individual	Steve Rueckert	WECC										X
33.	Individual	Chifong Thomas	Pacific Gas and Electric Company	X		X		X					
34.	Individual	Stephen R. Stafford	Georgia Transmission Corporation	X									
35.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
36.	Individual	Armin Klusman	CenterPoint Energy	X									
37.	Individual	Charles Lawrence	American Transmission Company	X									
38.	Individual	Alice Murdock Ireland	Xcel Energy	X		X		X	X				
39.	Group	Ben Li	IRC Standards Review Committee		X								

1. **Attachment B is intended to contain the test that the Planning Coordinators must use to determine whether a sub-200kV facility is critical to the reliability of the bulk power system. Do you agree that the method proposed in Attachment B is a technically sound approach to determine whether a sub-200kV facility is critical to the reliability of the bulk power system?**

Summary Consideration:

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	Support conformance with PRC-003 for all circuits 100 kV and above and as long as a reasonable period of time is allowed for proper implementation. However, some circuits could be prioritized based on their criticality to the system. The methodology in Attachment B should be considered as determining those circuits which should be prioritized first, followed by the remaining circuits 100 kV and above. Further clarification is needed for Criterion #2 because the circuits which make up an IROL can change depending upon the state of the system, while evaluation of relay loadability must be done in advance. The following language is proposed: Each circuit that is a monitored element of an IROL, assuming that all transmission elements are in service and the system is under normal conditions.Criterion #3 is unclear. The term “directly related to” (off-site power supply to nuclear plants”) is so broad that it essentially covers all transmission circuits that are connected to a nuclear plant. If this criterion meant to be the circuits that are directly connected to a nuclear plant, and which form a critical path to supply backup power to the plant, then the criterion should be clarified. For example, some plants may have low voltage (4160 V) cross-connects or distribution voltage (13.8 kV) circuits that provide off-site or qualified alternate AC power supplies to nuclear plants which are likely not going to be subject to relay loadability concerns due to transmission events (or such circuits may simply be providing power to office buildings). As written, it could be interpreted that such circuits may have to be considered as part of this requirement. This is unnecessary. This criterion needs to be revised such that lower voltage circuits which cannot be subjected to relay loadability concerns are explicitly excluded, and also to limit its applicability to circuits that provide critical off-site power to nuclear plants as identified in the Nuclear Plant Interface Requirements (NPIRs) provided by the Nuclear Plant Generator Operators to the applicable Transmission Entities in accordance with NUC-001-2.Criterion #4 does not belong in this standard, and should be eliminated. If the outage of an element causes unacceptable voltages elsewhere, appropriate actions should be taken to address and remediate this issue. Conformance with PRC-023 is not going to solve the undesired consequences of an outage, which could occur any time. NUC-001-2 already requires that the Nuclear Plant Generator Operator and the applicable Transmission Entities: o coordinate on the testing, calibration and maintenance of on-site and off-site power supply systems and related components (R9.3.3) o incorporate the NPIRs into their planning analyses of the electric system (R3) o incorporate the NPIRs into their operating analyses of the electric system (R4.1) o operate the electric system to meet the NPIRs (R4.2).Criterion #6 should be deleted. The PC and TP assess their future systems according to the performance requirements

Organization	Yes or No	Question 1 Comment
		stipulated in the TPL standards, including those in TPL-003. To require an entity to assess the impact of a contingency that is not required by TPL-003 would go beyond the basic planning and design requirements. Further, it raises the question on why do we single out the 100-200 kV facilities, but not all 200kV and above facilities? Requirement R1 in the recent draft PRC-023 already asks for setting transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating. This requirement is applicable for conditions with and without faults on the system, and is sufficient to cover the testing condition stipulated in the proposed Criterion #6. The system is neither planned nor operated to allow for two overlapping outages without operator action in between. If this criterion is retained, it should be made consistent with the requirements of TPL-003, where operator actions can be assumed between the first and second contingencies.
Pacific Northwest Small Public Power Utility Comment Group	No	The comment group agrees with all the criteria but number 6. Consider a local loop above 100 kV that is fed from a single radial tap from the BES. Some regions continue to treat such radially fed systems as BES due to the presence of normally open tie switches on the distribution system. It is conceivable that a multiple contingency within the loop could cause one or more of the remaining un-faulted lines within the loop to overload to beyond 115% of their short term ratings. While undesirable, such a scenario does not rise to the level of a BES event. Even if the lines cannot overload, entities will be required to run simulations to prove non-applicability where such systems should be excluded by simple inspection.The comment group suggests that radially operated (operated is the key word here) systems be excluded.
MRO's NERC Standards Review Subcommittee	No	In general, Midwest Reliability Organization's NERC Standards Review Subcommittee (NSRS) agrees with the proposed criteria. However, there should be further clarification and qualification of the criteria noted below.In the introduction, the wording of "determine if that circuit needs to be evaluated for conformance with PRC-023" does not clearly tie to Requirement R5.1 or use the same language. We suggest revised wording to more clearly refer to Requirement R5.1 by using the more similar language of, "determine the circuits that are critical to the reliability of the BES".For Criteria #4, add the qualification that the outage condition is assessed for the near term planning horizon (years 1 to 5), rather imply that the criteria includes consideration of the less certain longer term planning horizon (years 6 to 10). We suggest adding the words, "for the near term planning horizon", to the end of criteria #4.For Criteria #6, clearly limit the types of double contingencies that should be considered to those identified in TPL-003 (e.g. more severe Category B), rather than imply any and all double contingencies beyond TPL-003. In addition, there is no bound on all the N-1-1 contingencies that must be considered (in TPL-003, the planner is allow to at least restrict the scope of study to the more severe contingencies. We suggest revising the wording to, ". . . as a result of double contingencies that are required in the TPL-003 standard and in addition, the more severe contingencies of loss of a single circuit, followed by the loss of a second circuit, without system adjustments in between".We do not believe that a flowgate should be automatically included in the criteria. The NERC Glossary of Terms definition of flowgate would require every flowgate in the IDC to be identified. This is a problem because flowgates are included in the IDC for many reasons not just because reliability issues are identified. Flowgates could be included to simply study the impact of schedules on a particular interface as an example. It does not mean the interface is critical.

Organization	Yes or No	Question 1 Comment
		Furthermore, the list of flowgates in the IDC is dynamic. The master list of IDC flowgates is updated monthly and IDC users can add temporary flowgates at anytime. Criterion 1 would imply that any monitored facility then becomes subject to the standard. Furthermore, IDC is more of a congestion management tool than a reliability tool. FERC recognized this in Order 693, when they directed NERC to make clear in IRO-006 that the IDC should not be relied upon to relieve IROLs that have been violated. Rather, other actions such as redispatch must be used in conjunction. Thus, it would appear that inclusion of a flowgate in the IDC does not indicate that it is critical.For Criteria #5, we suggest that the applicable entities be changed. The Transmission Planner should be added because they have local planning responsibilities and knowledge that should be factored into the consideration of critical circuit classification. We suggest that the Regional Entity be removed because it does not fall within the Reliability Assurer functional tasks.
SERC Planning Standards Subcommittee	No	Although this question states Attachment B contains the critical facilities test, it instead appears to contain a listing of facilities to evaluate to determine if they are critical, and not the test itself. Attachment B states that if any of the criteria apply to a circuit, the circuit needs to be evaluated. It should state that the circuit should be considered critical.Item1 should be removed since not all flowgates are related to reliability. The remaining items adequately cover lines less than 200 kV that are critical to reliability.Item 3 contains a typo. Change "are" to "is."Item 3: The word "related" is too vague, recommend to use the word "connected" instead.Item 6 is confusing and should be revised as follows: "Each circuit operated between 100 kV and 200 kV that exceeds its Short Term Emergency Rating by 15 percent or more as a result of double contingency combinations selected by engineering judgment in TPL-003 Category C3, but without system adjustments in between." The comments expressed herein represent a consensus of theviews of the above-named members of the SERC EC Planning StandardsSubcommittee only and should not be construed as the position ofSERC Reliability Corporation, its board, or its officers.
Pepco Holdings, Inc. - Affiliates	No	Mitigation timeframes are identified on the unofficial comment form, which differ from those defined by the implementation plan in the most recent draft version of the standard. To be enforceable all mitigation timeframes need to be identified in the standard itself. Secondly, the mitigation timeframes in the comment form use phrases like “by the time the overload problem would be expected” and “before the operating time being analyzed”. The timeframe requirements for mitigation need to be better defined to be auditable. The Planning Coordinator needs to determine an “exact date” when the mitigation is required prior to the overload taking place. If that date is more than 24 months away then the protection system owner will have to mitigate the facility before the required date established by the Planning Coordinator. However, if the projected overload date is less than 24 months away, the protection system owner will have 24 months after being notified by the Planning Coordinator to mitigate the facility; and operators shall be made aware of the loadability limitation and should operate the facility accordingly until the facility is mitigated. The issue is that it may take 24 months for the protection system owner to make necessary hardware upgrades to mitigate the loadability limitation.
System Protection Department	No	1. We think that criterion 1 should be changed as follows “... Texas Interconnection, or path in the Western Interconnection that is listed as an Existing Path in the current year WECC Path Rating Catalog.” The current

Organization	Yes or No	Question 1 Comment
		wording “rated path in the Western Interconnection” is too general and could be interpreted to mean any element in the Western Interconnection that has a thermal rating.2. Change “are” in criterion 3 to “is.”3. We think that criterion 5 is too vague, may be discriminatory, is unnecessary, and should be removed. There is no basis listed for determining circuits in this criterion, the criterion may be applied discriminatorily or differently even within the same interconnection, it potentially excludes the protection system owner from having input in the process, and there is no redress for appeal by the owner. Protection system owners do not want transmission elements to be removed from service due to loading and nothing precludes a protection system owner from applying PRC-023 requirements to lower voltage lines. We also think that getting agreement between the three required entities could be troublesome.If some form of criterion 5 is included in the Attachment B, then it needs to define a technical basis for the request for inclusion, a procedure to initiate the request for inclusion, due process defined for evaluation of the request, and inclusion of the protection system owner in the evaluation process and the agreement. It seems that criterion 6 defeats the need for criterion 5.4. We think that criterion 6 should be revised to read as “Each transmission line operated between 100 kV and 200 kV that exceeds its highest seasonal 15-minute Facility Rating or each transformer operated between 100 kV and 200 kV that exceeds its operator established emergency transformer rating as a result of a double contingency...” The current wording would have no positive impact on BES reliability. First, the existing term “Short Term Emergency Rating” is not defined and is not used in PRC-023. We are suggesting changing the concept to terms that are used in the standard. Secondly, nothing in PRC-023 requires the protection system owner to set the relays to operate at more than 115% of an emergency rating or a short term (15-minute) rating. An element loading that qualifies under the drafting team's proposed criterion 6 would not have to be considered unless it exceeded the 115% of the emergency or short term rating, which the protection system settings would not be required to permit per the requirements of PRC-023. That is why we changed the criterion to indicate inclusion of the element for any loading that exceeded the emergency or short term rating for the contingencies studied.
FirstEnergy	No	FirstEnergy has the following comments related to the proposed criterion presented in the Attachment B of PRC-023-2. A. Consistency with the CIP-002-4 bright-line criteria. When comparing the proposed PRC-023-2 Attachment B criterion to the bright-line criteria proposed for CIP-002-4 Attachment 1 Critical Asset determination there is a great deal of overlap in concepts presented for transmission facilities. For example, each cover aspects of transmission facilities associated with IROLs and transmission facilities that are operationally significant for the safe operation and shutdown of a nuclear generation plant. Since these are parallel standard development efforts we suggest to the extent possible the PRC team and CIP team use consistent language when equivalent technical concepts are utilized for critical facility determinations. FirstEnergy's suggested changes identified below for the six individual criterion are consistent with CIP-002-4 Attachment 1 proposals made by FirstEnergy. B. Leverage existing studies and analysis - planning timeframe. We concur with the drafting team’s perspective that tests for the applicability of PRC-023 should leverage as much existing work as possible, however, FE believes any study/analysis work should be limited to that performed by the planning coordinators and transmission planners and not the transmission operators as

Organization	Yes or No	Question 1 Comment
		suggested by the comment form background information. FE believes the appropriate timeframe to identify the sub 200kV critical facilities is the planning horizon based on forward looking studies conducted by or under the supervision of the planning coordinator. This is consistent with PRC-023-1 (R3) and the proposed PRC-023-2 (R5) since the planning coordinator is the applicable entity required to determine the sub 200kV critical facilities and the time-horizon for the requirement is long-term planning. Information based on analysis performed by the reliability coordinator or transmission operator within the operating time horizon, such IROL, can be temporary, dynamic and subject to change. Therefore, it should be clear that the intent of facilities associated with IROLs are based on planning timeframe analysis. See FE's proposed changes to the second criterion. C. Mitigation Timeframes. The comment form provided by the drafting team presented two criteria for mitigation timeframe. This information should not be buried in a comment form but rather part or the standard's Effective Date's section (Section 5) and presented in an Implementation Plan so that it may be fully vetted by industry through the standards development process. The mitigation timeframe should be clear that the minimum expectation is 24-months upon the asset owner being notified by the planning coordinator of a new critical facility determination. The first bulleted item presented by the team is vague if its meant to be the "greater of" or "lesser of" 24 months or the time the overload problem would be expected. As stated above, FE believes that critical facility determinations are appropriately based on planning horizon timeframes and therefore it should be clear that an asset owner is afforded a minimum 24-month period to mitigate any critical facility required to meet PRC-023. This is consistent with the approved version 1 and the proposed version 2 standard.D. Specific comments on the Attachment B Criterion.i. Criteria 1: A flowgate should not be automatically included in the criteria. The NERC Glossary of Terms definition of flowgate would require every flowgate in the IDC to be identified. This is a problem because flowgates are included in the IDC for many reasons not just because reliability issues are identified. Flowgates are used for market recognition to study the impact of schedules on a particular interface and may not present a reliability concern. The team should consider a more limiting use of flowgate or striking the criteria.ii. Criteria 2: FE agrees with the concept of associating a critical facility with IROL however we believe two important revisions are required. First, the critical facility should be based on the contingent facilities that describe the IROL and not the monitored elements. Second, the IROL determinations should be based on planning horizon studies. FirstEnergy proposes the following text for criteria 2: "Transmission Facilities that the Planning Coordinator or Transmission Planner designates that, if destroyed, degraded, misused or otherwise rendered unavailable, demonstrates the need for an Interconnection Reliability Operating Limit (IROL)."iii. Criteria 3: FE supports criteria 3 and proposes revision so that criteria 3 reads “BES Facilities providing offsite power requirements as identified in the Nuclear Plant Interface Requirements.”iv. Criteria 4: Criteria 4 should be removed since criteria 3, as revised above, should adequately cover the transmission facilities deemed critical for a nuclear generation facility as designated in their NPIRs.v. Criteria 5: Criteria 5 is vague, open ended and should be removed. Any criteria that the PC may use to include other facilities should be explicitly stated in Attachment B. The RC should be removed since it makes evaluations within the operating horizon timeframe which is not appropriate for requirement R5.vi. Criteria 6: FE supports this criteria.

Organization	Yes or No	Question 1 Comment
Midwest ISO Standards Collaborators	No	We have many concerns with the approach identified. We do not believe that a flowgate should be automatically included in the criteria. The NERC Glossary of Terms definition of flowgate would require every flowgate in the IDC to be identified. This is a problem because flowgates are included in the IDC for many reasons not just because reliability issues are identified. Flowgates could be included to simply study the impact of schedules on a particular interface as an example. It does not mean the interface is critical. Furthermore, the list of flowgates in the IDC is dynamic. The master list of IDC flowgates is updated monthly and IDC users can add temporary flowgates at anytime. Criterion 1 would imply that any monitored facility then becomes subject to the standard. Furthermore, the IDC is more of a congestion management tool than a reliability tool. FERC recognized this in Order 693, when they directed NERC to make clear in IRO-006 that the IDC should not be relied upon to relieve IROLs that have been violated. Rather, other actions such as redispatch must be used in conjunction. Thus, it would appear that inclusion of a flowgate in the IDC does not indicate that it is critical.For criterion 2, we believe any contingent facility or prior outage that sets up the IROL should be included if criterion 6 is revised to allow operator intervention between contingencies. If criterion 6 is not revised, we do not support adding contingency or prior outages.For criterion 3, what does it mean to be directly related to the off-site supply to nuclear plants? Does this means it is identified in the NPIRs associated with the agreements mandated by NUC-001-2? This criteria needs to be further refined if retained.For criterion 4, since NERC standards collectively require us to operate the system to N-1 and to plan the system with Category C contingencies, this criterion should never identify any facilities with low voltage.For criterion 5, this criterion is too open ended and should be eliminated. Since the Regional Entity is the auditor, they should not provide direct input into what is included. This seems like carte blanche for the Regional Entity to add to the list of facilities whenever the latest issue arises. Could we end up having a situation where after every event analysis the Regional Entity identifies even more facilities? If the Regional Entities have needs to identify facilities they should do this by providing input through the standards development process to suggest modifications to the criteria. Will the RC and PC be judged similar to how entities are currently being judged regarding the number of Critical Assets that have been identified for CIP? If so, this could become a “bring me a rock” exercise. If the PC and RC don’t identify enough facilities, will the ERO and Regional Entities pressure them to identify more? Industry will be better served if we eliminate this open ended criteria and just identify bright line criteria for what should be included. This really seems like a catch all in case we forget to add all the necessary criteria.For criterion 6, we disagree with this criterion because it exceeds what is required in the TPL standards. For category C3 contingencies, the Planning Coordinator is allowed to assume operator intervention between the first and second independent contingency. Further, this even exceeds what FERC ordered in their directive in paragraph 79 from Order 733 which states: “To achieve this goal, the test to determine which sub-200 kV facilities are subject to PRC-023-1 must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning.” This proposed criterion is not consistent with the TPL standards but rather exceeds those standards.
Dominion	No	While items 1-5 seem reasonable, Dominion takes exception with item six (6). Item six goes beyond TPL-003

Organization	Yes or No	Question 1 Comment
		criteria, by assuming the operator will have no time between contingency events to make system adjustments. TPL-003 was thoroughly vetted when it was developed and is sound criteria that has been in place for years. Circuits below 200 kV are less critical to the security of the bulk electric system. We see no reason why the standard should not allow that the operator will make system adjustments between the first and second contingency.
Bonneville Power Administration	No	BPA would like to raise the concern regarding the terminology being used in PRC-023. An underlying principle of the standard is to "Determine which of the facilities in its Planning Coordinator Area are critical to the reliability of the BES...". BPA would like to take this opportunity to point out that determination of “critical” as PRC-023 is applied may not be directly reflective of CIP Critical Asset identification. BPA feels this is appropriate due to the guidance provided in CIP-002 R1 where the Risk-Based Assessment Methodology should include the following considerations (as we used to develop BPA's methodology): 1) Control centers and backup control centers; 2) Transmission substations that support the reliable operation of the Bulk Electric System; 3) Generation resources that support the reliable operation of the Bulk Electric System; 4) Systems and facilities critical to system restoration, including blackstart generators and substations in the electrical path of transmission lines used for initial system restoration; 5) Systems and facilities critical to automatic load shedding under a common control system capable of shedding 300 MW or more; 6) Special Protection Systems that support the reliable operation of the Bulk Electric System; and 7) Any additional assets that support the reliable operation of the Bulk Electric System that the Responsible Entity deems appropriate to include in its assessment. No minimum kV levels are instructed to be specifically used to identify CIP Critical Assets where PRC-023 is heavily driven by kV levels. BPA believes it would be very labor intensive to try and come up with which circuits would exceed the STE rating by 15% or more. BPA would like to understand the benefit of this study to increasing reliability.For Attachment B, BPA believes the performance requirement needs to be clarified further. The term "double contingency" and reference to "TPL-003" needs to be more specific, since TPL does cover more than just N-2 contingency of circuit elements. Additionally, regarding the Standard itself, for some local areas, if three lines are feeding the local area and it has been planned per the Standards (e.g. one single 115 kV line can't feed 100% of load in the area for loss of the other two), it seems like if two of the lines are lost simultaneously, then loss of the third line quickly, rather than waiting for an operator response may be preferable. This could be a safety issue and the operator may have no control over outcome. Additional comments:BPA would find it helpful if the drafting team were to create a cross-walk of the FERC directives (as listed on Page 3 and 4 of the SAR) and how/where the drafting team is addressing them.
PacifiCorp	Yes	
Arizona Public Service Company	Yes	
East Kentucky Power Cooperative, Inc.	No	East Kentucky Power Cooperative (EKPC) agrees in principle with the establishment of criteria to be used to identify circuits to be evaluated for conformance with PRC-023-2. However, EKPC does not believe that all of the proposed criteria are appropriate. For instance, the first listed criterion that specifies any circuit listed as the monitored element of a flowgate appears to be excessive. EKPC does not believe that flowgates necessarily correspond with a critical facility requiring further analysis of relay settings. EKPC also does not agree with the

Organization	Yes or No	Question 1 Comment
		6th listed criterion as stated. We propose that the criterion be modified to allow system adjustments between contingencies in accordance with the TPL-003 standard. EKPC feels that this criterion stated in Attachment B should maintain consistency with the requirements for system performance stated in TPL-003. With the elimination of the first criterion listed in Attachment B and the modification of the 6th listed criterion to allow system adjustments between contingencies, EKPC would support the method listed in Attachment B for identification of critical circuits.
Southern Company	Yes	For clarity, it is suggested that the two sentences above the criteria list of Attachment B be revised as follows: Review each (line and transformer) circuit less than 200 kV against the following criteria to determine if that circuit must conform with PRC-023. If any of the criteria below apply to the circuit under review, the circuit must conform to the requirements of PRC-023.
Salt River Project	No	There is an error in the wording under R5, this requirement states "transmission lines operated at below 200kV and transformers below 230kV." It should state "transmission lines operated between 100kV and 200kV and transformers operated between 100kV and 200kV" otherwise this standard will fall out of the definition of BES.
Operational Compliance	Yes	We would like to propose a rewrite for criterion #6. The proposed rewrite is:"Each circuit operated between 100 kV and 200 kV that exceeds its short term Emergency Rating by 15% or more as the result of a double contingency, beyond the requirements of TPL-003 C3 (i.e. loss of a single circuit followed by the loss of a second circuit without manual system adjustments in between), for all combinations selected by engineering judgment in the TPL-003 C3 analyses." Note - This modified TPL-003 C3 contingency reflects a situation where a System Operator may not have time between two contingencies to make appropriate system adjustments.The term “Short Term Emergency Rating” is not a defined term so “short term” should not be capitalized and could potentially be removed. The definition of Emergency Rating specifies a finite time period. The addition of the word 'manual' before 'system adjustment' mirrors the TPL-003 C3 definition and better clarifies what is meant by 'system adjustment' as this is not a defined term. This would then imply that automatic system adjustments that occur due to RAS and SPS operations, transformer tap changes and automatic switching of reactive resources would not constitute a 'system adjustment' in the context of this criterion (further supported by the note to criterion #6).
California ISO	No	Further clarifications to the criteria in Attachment B are required.
Piedmont EMC	Yes	I would like to have a provision in the Standard so that all radial transmission lines are excluded from this requirement since they are not used for load transfer. Otherwise, a lot of utilities will have to comply wiht this Standard by stating that we do not have any critical lines and have a letter from the TO stating that we don't have any critical lines.
Kansas City Power & Light	No	Do not agree with the approach in R5 and R5.1 in proposed Standard PRC-023-2 to dictate to the Planning Coordinator additional criteria beyond the TPL Standards to identify operating sensitivities. The proposed Appendix B proposes to establish additional considerations of facilities by which the Planning Coordinator must determine if those facilities are critical to the reliability of the BES. There are a variety of differing, and often complex, operating conditions that dictate the need for transmission facilities. The TPL standards require extensive studies of the transmission system be performed under steady state and dynamic conditions to

Organization	Yes or No	Question 1 Comment
		understand and identify sensitive areas of the transmission system and enable Reliability Coordinators to identify flowgates and other operating sensitivities in their respective regions. In light of the Reliability Coordinators awareness of transmission sensitivities through these studies, it seems unnecessary to dictate to the Reliability Coordinators additional criteria as proposed here in this Appendix B.
United Illuminating	Yes	We agree with the approach. We are concerned that the periodicity of the determination of the lines between 100 kV and 200 kV is not specified in Attachment B number 6 or R5. Is this an annual determination or performed only when a study for the Planning Horizon is completed. Is the study period the short term planning horizon (1-5 year) or long-term planning horizon (6-10 year)? For a temporary maintenance condition, e.g. a line is removed from service for 14 months, is the PC required to reevaluate the list of facilities?
Ingleside Cogeneration, LP	No	In paragraph 97 of Order 733, FERC allows for entities to challenge the identification of sub-200 kV transmission facilities as critical to the BES. The paragraph reads as follows:"Finally, commenters argue that there should be some mechanism for entities to challenge criticality determinations. We agree that such a mechanism is appropriate and direct the ERO to develop an appeals process (or point to a process in its existing procedures) and submit it to the Commission no later than one year after the date of this Final Rule."Most of the proposed criteria leverage well-understood concepts such as violations of IROLs or double contingencies. However, the proposed attachment includes a catchall statement under Criterion #5 that the RC, PC, and RE can designate circuits as critical without any defined basis. This makes an appeals process imperative since there are economic impacts to facility owners of such designations. This process needs to be proposed and evaluated by the industry concurrently with Appendix B, not at a future date.
ISO New England Inc.	No	General comment: ISO New England supports conformance with PRC-003 for all circuits 100 kV and above allowing for a reasonable period of time for proper implementation. However, some circuits could be prioritized based on their criticality to the system. The methodology in Attachment B should be considered as determining those circuits which should be prioritized first, followed by the remaining circuits 100 kV and above. Comments regarding specific criteria:2. Further clarification is needed regarding criterion #2, since the circuits which make up an IROL can change depending upon the state of the system while evaluation of relay loadability must be done in advance. We proposed the following language: Each circuit that is a monitored element of an IROL, assuming that all transmission elements are in service and the system is under normal conditions."3. The breadth of criterion #3 is unclear and may, as written, be broader than necessary or appropriate. For example, some plants may have low voltage (4160 V) cross-connects or distribution voltage (13.8 kV) circuits that provide off-site or qualified alternate AC power supplies to nuclear plants which are likely not going to be subject to relay loadability concerns due to transmission events (or such circuits may simply be providing power to office buildings). As written, it could be interpreted that such circuits may have to be considered as part of this requirement, and we believe this to be unnecessary. This criterion needs to be modified such that lower voltage circuits which cannot be subjected to relay loadability concerns are explicitly excluded and also to limit its applicability to circuits that provide critical off-site power to nuclear plants, as identified in the Nuclear Plant Interface Requirements (NPIRs) provided by the Nuclear Plant Generator Operators to the applicable Transmission Entities in accordance with NUC-001-2.4. Criterion #4 should be eliminated. NUC-001-2 already

Organization	Yes or No	Question 1 Comment
		requires that the Nuclear Plant Generator Operator and the applicable Transmission Entities: o coordinate on the testing, calibration and maintenance of on-site and off-site power supply systems and related components (R9.3.3) o incorporate the NPIRs into their planning analyses of the electric system (R3) o incorporate the NPIRs into their operating analyses of the electric system (R4.1) o operate the electric system to meet the NPIRs (R4.2).6. Criterion #6 is overly stringent and should be deleted. The system is neither planned nor operated to allow for two overlapping outages without operator action in between. If this criterion is retained, it should be made consistent with the requirements of TPL-003, where operator actions can be assumed between the first and second contingencies.
Manitoba Hydro	No	1) For criteria #5, Regional Entity does not need to be involved in determining the operational significant circuits. It should be changed to: “Each circuit determined and agreed to by the Reliability Coordinator and the Planning Coordinator.”2) For criteria #6, it should be clarified that it would be up to the Planning Coordinator to make the engineering judgment in determining the double contingencies beyond the requirements of TPL-003 standard. In addition, there should be some coordination between the methodology for critical asset determination in the cyber security standards and the relay loadability standard so multiple assessments are not required by the Planning Coordinator. Ideally, the scope of the TPL assessment should provide sufficient information for the other relevant NERC standards.
ComEd	Yes	Criteria number 6 calls for a test that includes comparison to the “Short Term Emergency Rating”. We have had some confusion on exactly which rating this refers to. Thus, our comment is to add some clarifications to this term. For example if this is the rating that is closest to a 15 minute highest seasonal facility rating, state this directly or in a footnote.
MidAmerican Energy	No	The proposed criteria is not technically sound as many of the criteria are completely arbitrary and have no technical basis. The appropriate basis for a critical element is something that could result in instability, uncontrolled separation, or cascading which is the basis for all NERC standards, the 2003 blackout, and the Energy Policy Act wording. The following proposed criteria is not technically sound and should be deleted:1. Being a flowgate or monitored element of a flowgate. The loss of a flowgate that doesn’t result in the instability, uncontrolled separation or cascading, may pose no more jeopardy to grid reliability than any other element that isn’t designated as a flowgate. This was proved by FERC’s own TIER report.2. A circuit agreed to by the RC, PC, and RE. This has absolutely no technical basis whatever and is completely arbitrary. This requirement also completely excludes the actual owner / operator of the facilities.3. A circuit that exceeds 15% of its short-term emergency rating as a result of a double contingency. This criteria exceeds what is required in the TPL standards. For category C3 contingencies, the Planning Coordinator is allowed to assume operator intervention between the first and second independent contingency. Further, this even exceeds what FERC ordered in their directive in paragraph 79 from Order 733 which states: “To achieve this goal, the test to determine which sub-200 kV facilities are subject to PRC-023-1 must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning.” This proposed criterion is not consistent with the TPL standards but rather exceeds those standards. This completely ignores any

Organization	Yes or No	Question 1 Comment
		unusual or temporary operating conditions that could result from ice storms or even maintenance practices.
MEAG Power	Yes	A minor clarification is needed. The first line under Criteria reads,"Review each circuit (line and transformer) less than 200 kV needs ..." It needs to be reworded as follows: "Review each circuit (line and low-side transformer) between 100 kV and 200 kV needs ..."The first line of number 6 needs to be reworded by deleting "between 100 kV and 200 kV." It would now read, " EAch circuit operated that exceeds its Short Term ..."
EROCT	No	In response to Attachment B of PRC-023, ERCOT ISO respectfully submits the following comments:Criterion 1 - the phrase “Commercially Significant Constraint in the Texas Interconnection” and the associated footnote should be removed. Commercially Significant Constraints (CSCs) are market-driven constraints designed to economically manage congestion under the ERCOT Zonal market construct. CSCs are not reliability constraints that reflect the criticality of an element relative to system reliability. Furthermore, as noted in footnote 1 in Attachment B, the ERCOT market is transitioning from the current Zonal construct to a Nodal construct on December 1, 2010. Under the Nodal design CSCs will not exist. Accordingly, the rules that apply to CSCs will expire prior to the implementation of this rule.Criterion 3 - The word “are” should be replaced with the word “is”.Criterion 4 - There should not be any circuits whose outage causes unacceptable voltages on the off-site power bus at a nuclear plant. Therefore, this criterion should be removed.Criterion 6 - Short Term Emergency Rating is not a defined term. Accordingly, it is not clear what rating is at issue. Emergency Rating is a defined term, and ERCOT assumes that is the rating envisioned by this criticality identifier. If that is the case, it needs to be clarified. If some other rating is envisioned, that too needs to be clarified, because, as noted, Short Term Emergency Rating is not defined.
American Electric Power	No	These AEP comments are provided in the context of the primary goal of this standard as specified under R5, "... to prevent cascading ...". The fundamental concern behind these comments is that the implemented methodology should not unnecessarily and erroneously classify facilities as “critical”, even for the limited purposes of this single standard. Such labels should only be applied to facilities that are truly “critical” to the reliability of the Bulk Electric System, and thus, the implemented methodology should only identify “critical” facilities. In addition, the implementation plan must allow for ample time to mitigate the initial wave of “critical” facilities that would reasonably be expected to be significantly larger than the incremental number of new “critical” facilities that will be identified on a routine basis going forward. Specific comments on the posted criteria being proposed by NERC are outline below.(1) Flowgates in the Eastern Interconnection (and Commercially Significant Constraints in the Texas Interconnection) are defined for various reasons and not just for reliability purposes. Flowgates are defined for interface monitoring, congestion management, and other purposes unrelated to reliability. Many of the flowgates reflect nominal normal and emergency ratings to limit loadings on these facilities below their thermal capabilities, and not for the purpose of preventing cascading. As such, being part of a flowgate definition alone should not be the basis for suspecting susceptibility to cascading, and thus, not a good reason for having such facilities meet the requirements of this standard. Furthermore, flowgates are updated on a continuous, and many times, temporary basis, and thus, not a practical basis for identifying facilities for the purposes of this standard. Therefore, this criterion should not be used as a basis for defining “critical” facilities for the purposes of this standard.(2) Since the identification of

Organization	Yes or No	Question 1 Comment
		"critical" facilities is made by the Planning Coordinators in the planning horizon (to give the relay owners ample time to address compliance with the requirements of this standard), then the IROL methodology that is applicable to the planning horizon (as specified under FAC-010) must be used to identify such "critical" facilities. In the case of PJM, IROL facilities in the planning horizon are those SOL facilities that have been identified as potentially resulting in cascading outages. As such, system reinforcements are developed in the planning horizon to ensure that such cascading conditions are mitigated and do not materialize in the eventual operating horizon. Consequently, PJM does not define any IROL facilities in the planning horizon. Therefore, this criterion can not be used as a basis for defining "critical" facilities in the planning horizon for the purposes of this standard. On the other hand, IROL facilities identified in the operating horizon (as specified under FAC-011), would be appropriate to use to identify "critical" facilities for the purposes of this standard.(3) On the surface, this appears to be a reasonable criterion. However, need to clarify what is meant by "directly related". If these are facilities that are identified under the NPIRs mandated under NUC-001, then their associated relay loadability performance should be addressed under NUC-001. Moving this requirement from PRC-023 to NUC-001 will ensure that all requirements associated with nuclear plants are addressed together under the same standard (NUC-001).(4) On the surface, this appears to be a reasonable criterion. However, when such voltage studies are conducted and unacceptable voltage conditions are identified in the planning horizon, system reinforcements and other mitigating actions are taken to ensure that such conditions do not occur in the operating horizon. Consequently, since no such conditions will be allowed to remain, then no "critical" facilities should result from this criterion. On that basis, this criterion should be eliminated. If the criterion is kept, then it should be moved under NUC-001 for the same reasons noted under criterion 3. Also, the criterion needs to specify the starting point of the outage analysis that identifies the unacceptable voltages. Furthermore, the outaged facility needs to be subject to heavy loadings to be considered for possible designation as a "critical" facility. The outage of the facility for reasons unrelated to heavy loadings should not be a basis for making that facility subject to the requirements of this standard.(5) This criterion is too open ended and should be eliminated. As the auditing entity, the Reliability Entity should not be providing any input outside of the auditing process. The Planning Coordinator has the flexibility to engage any other entities as it sees fit, and thus, there is no need to single out the Reliability Coordinator under this criterion. Also, even if these entities were kept and others, such as the Transmission Owners, were added, what would be the basis that these entities would use to identify these "critical" facilities? Again, this criterion is too open ended, it does not add anything meaningful to the effort, and thus, it should be eliminated.(6) On the surface, this appears to be a rational basis for identifying "critical" facilities since it utilizes cascading simulations. However, it stops short of performing the N-1-1-1 simulations (declares all overloaded facilities after the N-1-1 simulations as "critical" rather than going the extra step of performing the N-1-1-1 simulations to determine if any additional facilities become overloaded) that are needed to demonstrate susceptibility to cascading. Furthermore, an additional filter, one that takes into consideration the amount of load that would be placed at risk by the N-1-1-1 cascading scenario, also needs to be incorporated into this methodology. This can best be achieved by giving the TOs an opportunity to review the preliminary results from their Planning Coordinator and to demonstrate to their Planning Coordinator as to

Organization	Yes or No	Question 1 Comment
		the amount of load that would be at risk through the cascading of the proposed "critical" facilities. If the TOs can successfully demonstrate to their Planning Coordinator that for certain facilities the amount of load that would be at-risk (from the cascading scenario) falls below a specified threshold level (to be determined by their Planning Coordinator), then those facilities would be excluded from the final list of "critical" facilities. In the end, this should be the only criterion that is used to identify "critical" facilities for the purposes of this standard. Regarding the use of Short Term Emergency Ratings in the simulations, it should be noted that most ratings used in planning base cases (the ones that would be used by the Planning Coordinator) are Long Term Emergency Ratings, and thus, converting such models to reflect Short Term Emergency Ratings just for the purposes of conducting these simulations would not be practical. Therefore, the specification should be made as a higher percentage of Long Term Emergency Ratings.
Minnesota Power	No	Minnesota Power recommends that the Standards Drafting Team consider changing item #6 to read as follows:Each circuit operated between 100 kV and 200 kV that exceeds its Short Term Emergency Rating by 15 percent or more as a result of a double contingency (for those combinations selected by engineering judgment in TPL-003 System Performance Following Loss of Two or More BES Elements analyses).
Independent Electricity System Operator	No	We agree with Criteria # 1, 2 and 5, but do not agree with Criteria #3, #4 and #6.Criterion #3 is unclear. The term "directly related to" (off-site power supply to nuclear plants" is so broad that it essentially covers all transmission circuits that are connected to a nuclear plant. If this criterion meant to be the circuits that are directly connected to a nuclear plant and which form a critical path for supply backup power to the plant, then the criterion should say so to provide better clarity.Criterion #4 does not belong in this standard. If the outage of an element causes unacceptable voltages elsewhere, appropriate actions should be taken to address and remediate this issue. Conformance with PRC-023 is not going to solve the undesired consequences of an outage, which could occur any time. Criterion #6 is troublesome and perhaps not needed. The PC and TP assess their future systems according to the performance requirements stipulated in the TPL standards, including those in TPL-003. To require an entity to assess the impact of a contingency that is not required by TPL-003 would go beyond the basic planning and design requirements. Further, it raises the question on why do we single out the 100-200 kV facilities, but not all 200kV and above facilities? Requirement R1 in the recent draft PRC-023 already asks for setting transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating. This requirement is applicable for conditions with and without faults on the system, and is sufficient to cover the testing condition stipulated in the proposed Criterion #6. We suggest to remove this Criterion #6.
Ameren	No	Criterion #1 : A monitored flowgate does not imply a reliability issue. Flowgates are monitored for many reasons, some for reliability and some to regulate the amount of firm transmission service. In non-FTR markets, firm transmission monitoring may be a partial function of reliability. However, in FTR markets, the sale of firm transmission service may be related to the acquisition of ARR/FTRs. Under these scenarios, the flowgate may be in place to ensure FTR funding sufficiency. Circuits with high degrees of uncertain loading are most susceptible but the mere presence of uncertainty does not make them critical for the reliability of the BES.Criterion #2: We are ok with the element related to "IROL" type criterion including outage of such element

Organization	Yes or No	Question 1 Comment
		causing instability or cascading effect on the BES. Criterion #3: We believe that our comment should be restated as “This criterion should not be included in a relay loadability test. The fact that a circuit supplies a reserve aux transformer at a nuclear plant does not make the circuit critical to the transmission network or to the plant. If the outage of a circuit results in the outage or instability of a nuclear plant, then these issues should have been addressed in the design of the plant supply and/or in the TPL-002 assessment.”Criterion 4: This issue should be covered in TPL-002 or NUC-001. This item should not be included in a relay loadability test.Criterion #5: This is an open-ended criterion without any supporting basis. It is also unclear who at the Regional Entity would “sign-off”, Compliance, Engineering, or someone else? Further, this type of criterion would introduce more inconsistencies rather uniformity. If such a criterion is used, we suggest that the RC, PC, and/or RE should work closely with the local Transmission Planners to determine if a circuit should be assessed for criticality and further subjected to the relay loadability test.Criterion #6: Short Term Emergency Rating, although capitalized in here, is not a NERC defined term. Further, the criterion does not identify the time duration that the STE rating would be applicable, nor the basis for such a rating. If a common time duration and basis for rating could be established, a common loading above the STE rating could be established. A loading of 120% may be more indicative of a cascade than 115%, and would be applicable for fast acting contingencies involving multiple circuits, including Category C1 bus faults, C2 breaker failures, or C5 double-circuit tower outages. We do not agree with the proposal that system adjustments would not be allowed for slower multiple contingency Category C3 events (sometimes referred to as N-1-1 outages) involving lines, generators or transformers, as this requirements clearly steps on standard TPL-003.
WECC	No	The approach described is reasonable, however, it would be more comprehensive and consistent to replace in item 1 (Attachment B), "rated path in the Western Interconnection" with "paths included in Table of Major WECC Transfer Paths in the Bulk Electric System". This Table is more comprehensive because it is identified by the WECC Operating Committee and is consistent with the major paths used in other WECC Standards.Item 5 appears vague. What does “agreed to by the Reliability Coordinator, the Planning Coordinator, and Regional Entity mean?” Do all three need to be in agreement before a facility is to be added to the list to be evaluated, or can any one of them add it to the list? How are these entities supposed to come to agreement and document that agreement. If there is not a proactive effort to develop the list and “agree” to it, there probably won’t be a list.I’m not sure I understand Item 6. Does this mean that results of TPL-003 assessments will helpt identify circuits that have to be evaluated? TPL-003 is eventually going to go away when the ATFNSDT effort is completed. The requirement to conduct the types of assessments currently included in TPL-003 will not go away, but the specific referenct to TPL-003 could become obsolete.
Pacific Gas and Electric Company	No	We believe the approach described is reasonable, however, as written Item 1 (Attachment B) concerning WECC paths is vague. We suggest, replacing "rated path in the Western Interconnection" with "paths included in Table of Major WECC Transfer Paths in the Bulk Electric System". We believe referencing this Table would provide clarity because the paths in this Table are identified by the Operating Committee in WECC and are consistent with the major paths used in other WECC Standards, such as FAC-501-WECC-1, PRC-004-WECC-1, and TOP-007-WECC-1.

Organization	Yes or No	Question 1 Comment
Georgia Transmission Corporation	No	Criterion 6 of Attachment B states "Each circuit operated between 100 kV and 200 kV that exceeds its Short Term Emergency Rating by 15 percent or more as a result of a double contingency..." The basis for the 15 percent criterion has not been clearly explained. What is the basis for this criterion? Based on this criterion, multiple lines could be identified as critical facilities, when, in fact, loss of these lines could have no significant impact to the BES(i.e. not cause cascading outages on the BES).
Duke Energy	No	o General Comment - It should be made clear that the application of these criteria is intended to determine which facilities must be evaluated for applicability of PRC-023-2 and may not necessarily dictate modification of relay settings. Situations where there is time for operator intervention, or no cascading, wouldn't need loadability protection. o Criteria 1 - We do not believe that flowgates should be automatically included as a criteria, since a flowgate may be in the IDC for business reasons. Also, the list of flowgates is dynamic. o Criteria 2 - Monitored elements of an IROL are also dynamic and we question how you could apply this in the planning timeframe so it could be used to set relays. IROLs identified in the planning horizon should be mitigated by some action prior to reaching the operating horizon. This criteria is not specific enough to be applied consistently. o Criteria 3 - What is meant by "directly related"? There is a difference between normal off-site power and emergency power. We don't think the NPIRs would clarify this situation. Is the expectation that no lines connected to a nuclear plant trip except for a fault on the line? o Criteria 4 - If we had such a circuit it would violate TPL-002 as well as the NPIRs, so this is not a useful criteria, because you'll never identify anything with it. o Criteria 5 - It doesn't make sense to include the Regional Entity, because the Regional Entity doesn't do the analysis. Also, this criteria just says you can go beyond the existing criteria, which is always an option - so why include it as a criteria? o Criteria 6 - "Short Term Emergency Rating" is not a defined term. However its use in conjunction with the 15% overload suggests that a 15-minute Emergency Rating is what is intended. Some Transmission Owners haven't determined sufficiently short term Emergency Ratings to meet the intent of this criteria, and if they set their relays at 115% of their shortest term Emergency Rating they would restrict loadability more than the standard should allow. Regardless of how the criteria for contingency line loading are defined in Attachment B, the criteria should match the requirements of PRC-023-2.
CenterPoint Energy	No	Considering situations where the transmission system may be at risk of cascading outages or voltage collapse, CenterPoint Energy believes sub-200 kV elements should be considered operationally significant only whenever reasonably contemplated scenarios would cause high amperage and low voltage to be experienced on the elements. Criteria 6 that proposes loading greater than 15% of the short term emergency rating following a double contingency is not a technically sound method to indicate if an element is operationally significant. CenterPoint Energy recommends only criteria 1 through 5 be used to determine whether a sub-200 kV element is operationally significant to the reliability of the bulk power system.
American Transmission Company	No	In general, we agree with the proposed criteria. However, we propose the following changes to the introduction, Criteria #4 and Criteria #6. [[1]]- In the introduction, the wording of "determine if that circuit needs to be evaluated for conformance with PRC-023" does not clearly refer to Requirement R5.1 or use the same language as R5.1. We believe that the wording in Attachment B should match the wording in R5.1. However, use of the terminology, "critical to reliability of the BES", keeps causing confusion with the meaning of the

Organization	Yes or No	Question 1 Comment
		concept of "critical" as it is defined in the CIP-002 standard. Therefore, we propose replacing the "critical" terminology in R5.1 with distinctly different terminology like, "that have major operational significance to the reliability of the BES". Then, use wording similar to R5.1 in Attachment B such as, "determine the circuits that have major operational significance to the reliability of the BES". [[2]]- For Criteria #4, add the qualification that the outage condition is assessed for the near term planning horizon (years 1 to 5), rather imply that the criteria includes consideration of the less certain longer term planning horizon (years 6 to 10). We suggest adding the words, "for the near term planning horizon", to the end of criteria #4. [[3]]- For Criteria #6, clearly limit the types of double contingencies that should be considered to those identified in TPL-003 (e.g. more severe Category B), rather than imply any and all double contingencies beyond TPL-003. In addition, there is no bound on all the N-1-1 contingencies that must be considered (in TPL-003, the planner is allow to at least restrict the scope of study to the more severe contingencies. We suggest revising the wording to, ". . . as a result of double contingencies that are required in the TPL-003 standard and in addition, the more severe contingencies of loss of a single circuit, followed by the loss of a second circuit, without system adjustments in between".
Xcel Energy	No	Item 1 - it is not clear how 'temporary flowgates' would be considered I this application; "commercial" considerations should not be part of a reliability standard; "rated path" in WECC is not clear - are these any path in the WECC Path Catalog, or is it intended to mean the "Major WECC Paths..."?Item 4 - we feel it should be eliminated from the list of criteria. Since NERC standards collectively require us to operate the system to N-1 and to plan the system with Category C contingencies, this criterion should never identify any facilities with low voltage.Item 5 - this appears to give carte blanche authority to the PC/RC/RE to decide a circuit is subject to evaluation; we believe this should be tempered with concurrence from the TO/GO/DP.
IRC Standards Review Committee	No	Criterion 1 is inappropriate and should be eliminated. It states that any monitored facility below 200KV would be subject to this standard. A facility that is designated as a flowgate should NOT be automatically assumed to have an impact on reliability. Flowgates are included in the IDC for many reasons and not always because the facilities are critical to bulk system reliability. Some flowgates are defined and included in the IDC only to have the PTDF, OTDF and LODF calculated. In general, flowgates are not a good indicator for reliability needs; the master list of IDC flowgates is updated monthly and IDC users can add temporary flowgates at anytime. Furthermore, IDC is primarily used to study congestion and is the basis of Transmission Loading Relief (TLR) which is not a reliability tool. FERC recognized this in Order 693, when they directed NERC to make clear in IRO-006 that the IDC should NOT be relied upon to relieve IROLs that have been violated and other actions such as redispatch must be used in conjunction with TLR. Criterion 2 should state that any contingent facility or prior outage that sets up the IROL be included, except where such facility is used as a proxy for assessing the IROL. Criterion 3 is unclear and should be clarified. What does it mean to be "directly related" to the off-site supply to nuclear plants? More clarity in the wording is needed. Is the intent that facilities that provide off-site power to nuclear plants as defined in the NPIRs associated with the agreements mandated by NUC-001-2 are captured in this standard?Criterion 4 is not needed since NERC standards already contain

Organization	Yes or No	Question 1 Comment
		requirements to operate the system to N-1 and to plan the system with Category C contingencies. Therefore, this criterion would never identify any facilities whose outage would cause low voltage.Criterion 5 is too open ended and should be eliminated. The Regional Entity serves primarily as the compliance enforcement authority and not the technical assessor of what facilities are critical for bulk power reliability. They do not perform any of the operating and planning functions required to comply with reliability standards. These criteria should strive to be as close as possible to “bright line” tests. Criterion 5 is in a sense rhetorical, like defining a word with the same word.Criterion #6 should be deleted. This criterion does not recognize that the system is neither planned nor operated to allow for two overlapping outages without operator action in between. This goes beyond the assessment and performance requirements of TPL-003, where operator actions can be assumed between the first and second contingencies. We also ask why a 15% over Short Term Emergency Rating is an appropriate level, there is no justification.

END OF REPORT

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form for Relay Loadability Order (No. 733) (Project 2010-13)

Please **DO NOT** use this form. Please use the electronic form located at the link below to submit **FORMAL** comments on the proposed second version of the Relay Loadability Standard PRC-023-2 that includes the applicability test in Attachment B. The electronic comment form must be completed **by December 16, 2010.**

If you have questions please contact Joe Bucciero at joe.bucciero@gmail.com or by telephone at 267-981-5445.

Background Information

NERC Standard PRC-023-1 – Transmission Relay Loadability was approved by FERC as mandatory and enforceable in March 2010, with direction that NERC make a number of changes.

The Standard Drafting Team made changes to PRC-023-1 to address the following directives from Order 733

- p. 60 . . . modify PRC-023-1 to apply an "add in" approach to sub-100 kV facilities that are owned or operated by currently-Registered Entities or entities that become Registered Entities in the future, and are associated with a facility that is included on a critical facilities list defined by the Regional Entity.

- p. 186 . . . require that transmission owners, generator owners, and distribution providers give their transmission operators a list of transmission facilities that implement sub-requirement R1.2.

- p. 203 . . . modify sub-requirement R1.10 so that it requires entities to verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with the fault.

- p. 224 . . . make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant to sub-requirement R1.12.

- p. 237 . . . modify the Reliability Standard to add the Regional Entity to the list of entities that receive the critical facilities list. [sub-requirement R3.3]

- p. 244 . . . include section 2 of Attachment A in the modified Reliability Standard as an additional Requirement with the appropriate violation risk factor and violation severity level.

- p. 264 . . . revise section 1 of Attachment A to include supervising relay elements on the list of relays and protection systems that are specifically subject to the Reliability Standard.

- p. 283 . . . modify the Reliability Standard to include an implementation plan for sub-100 kV facilities.

- p. 284 . . . remove the exceptions footnote from the "Effective Dates" section.

The Standard Drafting Team posted the proposed changes for informal industry comment from August 19, 2010 to September 19, 2010. The proposed changes did NOT include Attachment B to the standard as it was still a work in progress at that time. Attachment B contains the applicability test that the Planning Coordinators must use to determine whether a sub-200kV facility must comply with PRC-023. The inclusion of a test is a directive in Order No. 733:

- p. 69 . . . modify Requirement R3 of the Reliability Standard to specify the test that planning coordinators must use to determine whether a sub-200 kV facility is critical to the reliability of the Bulk-Power System.

Requirement R6 of the draft PRC-023-2 standard (formerly Requirement R3 of PRC-023-1) states:

R6. Each Planning Coordinator shall apply the criteria in Attachment B to an assessment conducted at least once each calendar year, with no more than 15 months between assessments, to determine which transmission Elements must comply with this standard. The Planning Coordinator shall:
[Violation Risk Factor: High] [Time Horizon: Long Term Planning]

6.1 Apply the criteria to transmission lines that are operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.

6.2 Apply the criteria to transmission lines operated below 100 kV and transformers with low voltage terminal connections below 100 kV, if the Regional Entity has identified either of these Element types as critical facilities for the purposes of the Compliance Registry and they are in its Planning Coordinator Area.

6.3 Maintain a list of facilities determined according to the process described in Requirement R6.

6.4 Include on the list the year studied for which criterion B4 in Attachment B first applies when a facility is added and only criterion B4 is applicable.

6.5 Provide a list of facilities 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.

In response to comments during the informal posting the SDT has replaced the phrase “critical to reliability of the bulk electric system” with “must comply with this standard.” The SDT notes that although the phrase “critical to reliability of the bulk electric system” appears in the approved PRC-023-1 and is used in Order No. 733, the SDT recognizes that use of the same or similar terms in multiple standards will result in confusion.

Use of the phrase “critical to reliability of the Bulk Electric System” in PRC-023 is intended to have meaning specific to the issue of relay loadability; specifically to identify facilities, that if they trip due to relay loadability following an initiating event, may contribute to undesirable system performance similar to what occurred during the August 2003 blackout. Reliability is adequately addressed in Attachment B since it identifies all of the facilities that must be subject to this standard to maintain reliability of the Bulk Electric System.

A Blue Ribbon Panel was formed by NERC to develop that required Attachment B to PRC-023-2, which was separately posted for informal industry comment from September 23, 2010 to October 12, 2010.

Applicability Testing Criteria

NERC Reliability Standard PRC-023 — Transmission Relay Loadability was developed in answer to relay loadability problems highlighted during the blackout of 2003. Relay loadability has been either causal or contributory to a majority of major system disturbances dating back to the 1965 blackout and beyond. The proposed Standard is intended to prevent circuits from prematurely tripping due to relay loadability when thermally overloaded. The concept is to allow some time for system operators to intervene and alleviate the overloads.

If any circuit trips under adverse conditions, even if the loss of that circuit does not itself cause a cascade, the resultant weakened transmission system leaves the bulk electric system more exposed to possible cascading outages. Therefore, applicability of PRC-023 should not only be for operationally significant circuits that could cause a cascade, but also for circuits that are prone to overloads (relievable through operator action) during contingencies.

Planning coordinators test for conformance with the TPL standards through various contingency analyses that should prevent critical circuits from becoming overloaded. The TPL criteria contingencies studied normally screen for susceptibility to cascading and system instability. However, overloading of circuits for short periods of time is permissible, and assumes operator action can alleviate such overloads in a timely fashion. Although the planning tests are fairly rigorous, they are usually limited to N-1 or N-2 level contingencies. However, it is for the unforeseen combinations of outages that assurance is necessary that circuits would not trip for relay loadability reasons.

The recommendations stemming from the 2003 blackout called for review of circuits 200 kV and above. Logically, all circuits, including those below 200 kV, that are operationally significant to the reliability of the bulk electric system (BES) should be tested for susceptibility.

System studies go to great lengths to determine transfer capabilities on critical transmission interfaces. Planning and operational studies are routinely conducted to determine the transfer capabilities of circuits such as those that are part of interconnection reliability operating limits (IROLs), flowgates in the Eastern Interconnection, major transfer paths in the Western Interconnection, or comparable monitored elements in the Texas Interconnection or Québec Interconnection. Any circuit that is important enough to reliability to be actively managed to prevent overloads should also be important enough to prevent it from inadvertently tripping due to relay loadability for combinations of outages that are not normally tested.

Note: The criteria included in Attachment B define the family of circuits operated below 200 kV that must comply with PRC-023. If the protection systems on these circuits comply with the Requirements of PRC-023, no further action is necessary. Any protection systems that do not comply would require mitigation.

Implementation Timeframes

Requirement R1: the first day of the first calendar quarter after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first calendar quarter after Board of Trustees adoption except as noted below.

- For the addition to Requirement R1, criterion 10, to set transformer fault protection relays and transmission line 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, the first day of the first calendar quarter 12 months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 12 months after Board of Trustees adoption.
- For supervisory elements as described in PRC-023 - Attachment A, section 1.6, the first day of the first calendar quarter 24 months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 24 months after Board of Trustees adoption.

Requirements R2 and R3: the first day of the first calendar quarter after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

Requirements R4 and R5: the first day of the first calendar quarter six months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required the first day of the first calendar quarter six months after Board of Trustees adoption.

Requirement R6: the first day of the first calendar quarter 18 months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required the first day of the first calendar quarter 18 months after Board of Trustees adoption.

Requirement R7: the first day of the first calendar quarter after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

Questions

The SDT has considered all of the industry comments submitted during the informal comment period, and has revised and updated the PRC-023-2 standard to incorporate the comments received in this posting of the complete standard. Your responses to the following questions will assist the SDT for Project 2010-13 Relay Loadability Order 733 in finalizing the work for PRC-023-2 relative to the proposed modifications summarized above.

For each question, please indicate whether or not you agree with the requirement being proposed. If you disagree with the changes to the proposed requirement, please explain why you disagree and provide as much detail as possible regarding your disagreement including any suggestions for altering the proposed requirement that would eliminate or minimize your disagreement. The SDT would appreciate responses to as many of these questions as you are willing to supply.

1. Requirement R1 defines the criteria 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. Criterion 10 of Requirement R1 was modified to ensure that protection settings do not expose transformers to fault level and duration that exceeds their mechanical withstand capability. Do you agree with the

modification to criterion 10 in Requirement R1? If not, please explain and provide specific suggestions for improvement.

☐ Yes

☐ No

Comments:

2. Requirement R2 requires the evaluation of out-of-step blocking schemes to verify that the out-of-step blocking elements allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. Note this new Requirement R2 does not add a new obligation on Transmission Owners, Generator Owners, and Distribution Providers; it only explicitly states in PRC-023-2 an obligation that presently is included in Attachment A, section 2 of PRC-023-1. Do you agree with the requirement included in Requirement R2? If not, please explain and provide specific suggestions for improvement.

☐ Yes

☐ No

Comments:

3. Requirement R4 requires the Registered Entities that choose to utilize Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability to provide the Planning Coordinator, Transmission Operator, and Reliability Coordinator with a list of facilities associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. Do you agree with the requirement included in Requirement R4? If not, please explain and provide specific suggestions for improvement.

☐ Yes

☐ No

Comments:

4. Requirement R5 requires the Registered Entities that set transmission line relays according to Requirement R1 criterion 12 to provide a list of the facilities associated with those relays to the Regional Entity at least once each calendar year, with no more than 15 months between reports. Do you agree with the requirement included in Requirement R5? If not, please explain and provide specific suggestions for improvement.

☐ Yes

☐ No

Comments:

5. Requirement R6 requires each Planning Coordinator to apply the criteria in Attachment B to determine which transmission Elements must comply with this standard. Do you agree with the requirement included in Requirement R6? If not, please explain and provide specific suggestions for improvement.

☐ Yes

☐ No

Comments:

6. "Requirement R7 requires the Registered Entities to implement Requirement R1, Requirement R2, Requirement R3, Requirement R4, and Requirement R5 for each facility that the Planning Coordinator added to the list of facilities that must comply with this

standard (per Requirement R6) by certain dates following notification by the Planning Coordinator. Do you agree with the requirement included in Requirement R7? If not, please explain and provide specific suggestions for improvement.

☐ Yes

☐ No

Comments:

7. Attachment A, section 1.6 has been revised to avoid unintended negative impact on reliability associated with referring to "Protective functions that supervise operation of other protective functions." Section 1.6 has been revised to "Supervisory elements associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications" to be more specific to the concern stated in Order No. 733. Do you agree that this is an acceptable and effective method of meeting this directive? If not, please explain and provide specific suggestions for improvement.

   ☐ Yes

   ☐ No

   Comments:

8. Attachment B contains the test that the Planning Coordinators must use to determine which transmission elements (transmission lines operated below 200 kV and transformers with low voltage terminals connected below 200 kV) must comply with this standard. Do you agree that the method proposed in Attachment B is a technically sound approach? If not, please explain and provide specific suggestions for improvement.

   ☐ Yes

   ☐ No

   Comments:

Implementation Plan for PRC-023-2: Transmission Relay Loadability

Standards Involved

• PRC-023-2 —Transmission Relay Loadability

Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before the Transmission Relay Loadability standard can be implemented.

Proposed Effective Date

Requirement R1: the first day of the first calendar quarter after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first calendar quarter after Board of Trustees adoption except as noted below.

- For the addition to Requirement R1, criterion 10, to set transformer fault protection relays and transmission line 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, the first day of the first calendar quarter 12 months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 12 months after Board of Trustees adoption.
- For supervisory elements as described in PRC-023 - Attachment A, section 1.6, the first day of the first calendar quarter 24 months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 24 months after Board of Trustees adoption.

Requirements R2 and R3: the first day of the first calendar quarter after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

Requirements R4 and R5: the first day of the first calendar quarter six months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required the first day of the first calendar quarter six months after Board of Trustees adoption.

Requirement R6: the first day of the first calendar quarter 18 months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required the first day of the first calendar quarter 18 months after Board of Trustees adoption.

Requirement R7: the first day of the first calendar quarter after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

Applicability

Requirements within the proposed standard apply to:

4.1. Functional Entities:

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4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023 - Attachment A, applied to facilities defined in 4.2.1 through 4.2.6.

4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023- Attachment A, applied to facilities defined in 4.2.1 through 4.2.6.

4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023- Attachment A, applied according to facilities defined in 4.2.1 through 4.2.6, provided those facilities have bi-directional flow capabilities.

4.1.4 Planning Coordinators

4.2. Facilities:

4.2.1 Transmission lines operated at 200 kV and above.

4.2.2 Transmission lines operated at 100 kV to 200 kV that the Planning Coordinator has determined are required to comply with this standard.

4.2.3 Transmission lines operated below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry and the Planning Coordinator has determined are required to comply with this standard.

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

4.2.5 Transformers with low voltage terminals connected at 100 kV to 200 kV that the Planning Coordinator has determined are required to comply with this standard.

4.2.6 Transformers with low voltage terminals connected below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry and the Planning Coordinator has determined are required to comply with this standard

Other entities may be recipients of data as described in this standard, but have no requirements placed upon them.

Retired Standards

The following standard will be retired when PRC-023-2 becomes effective:

- PRC-023-1 — Transmission Relay Loadability will be completely retired once PRC-023-2 becomes effective as specified above.

Standard Development Roadmap

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

Development Steps Completed:

1. The Standards Committee approved the SAR for posting on August 12, 2010.
2. SAR posted for formal comment on August 19, 2010.
3. Standard posted for informal comment period on August 19, 2010.

Proposed Action Plan and Description of Current Draft:

This is the second draft of the standard developed to address the FERC directives in Order No. 733 and is posted for a 45-day formal comment period with concurrent ballot during the last 10 days of the comment period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop third draft of the standard and respond to comments.	December 2010 – January 2011
2. Conduct recirculation ballot of standard	January 2011
3. NERC Board approval	February 2011
4. Submit standard to FERC for approval	March 2011

A. Introduction

1. **Title: Transmission Relay Loadability**

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

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 Entities:

4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023 - Attachment A, applied to facilities defined in 4.2.1 through 4.2.6.

4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023- Attachment A, applied to facilities defined in 4.2.1 through 4.2.6.

4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023- Attachment A, applied according to facilities defined in 4.2.1 through 4.2.6, provided those facilities have bi-directional flow capabilities.

4.1.4 Planning Coordinators

4.2. Facilities:

4.2.1 Transmission lines operated at 200 kV and above.

4.2.2 Transmission lines operated at 100 kV to 200 kV that the Planning Coordinator has determined are required to comply with this standard.

4.2.3 Transmission lines operated below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry and the Planning Coordinator has determined are required to comply with this standard.

FERC Order 733, ¶60: Apply an "add in" approach to sub-100 kV facilities.

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

4.2.5 Transformers with low voltage terminals connected at 100 kV to 200 kV that the Planning Coordinator has determined are required to comply with this standard.

4.2.6 Transformers with low voltage terminals connected below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry and the Planning Coordinator has determined are required to comply with this standard.

5. **Effective Dates:**

FERC Order 733, ¶284: Remove the exceptions footnote from the "Effective Dates" section.

5.1. Requirement R1: the first day of the first calendar quarter after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first calendar quarter after Board of Trustees adoption, except as noted below.

5.1.1 For the addition to Requirement R1, criterion 10, to set transformer fault protection relays and transmission line 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, the first day of the first calendar quarter 12 months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 12 months after Board of Trustees adoption.

5.1.2 For supervisory elements as described in PRC-023 - Attachment A, section 1.6, the first day of the first calendar quarter 24 months after applicable regulatory approvals or in those jurisdictions where regulatory approval is not required, the first day of the first calendar quarter 24 months after Board of Trustees adoption.

5.2. Requirements R2 and R3: the first day of the first calendar quarter after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

5.3. Requirements R4 and R5: the first day of the first calendar quarter six months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required the first day of the first calendar quarter six months after Board of Trustees adoption.

5.4. Requirement R6: the first day of the first calendar quarter 18 months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required the first day of the first calendar quarter 18 months after Board of Trustees adoption.

5.5. Requirement R7: the first day of the first calendar quarter after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

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] [Mitigation 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:

[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.

- 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.

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 to the under any system configuration.

10. Set transformer fault protection relays and transmission line 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 and so that the relays do not operate at or below the greater of:

> FERC Order 733, ¶203: Modify sub-requirement R1.10 to verify equipment is capable of sustaining the anticipated overload associated with the fault.

- 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.

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[2].

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 verify that its out-of-step blocking elements 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]*

FERC Order 733, ¶244: Include section 2 of Appendix A as an additional Requirement.

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 a list of facilities 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]*

FERC Order 733, ¶186: Modify R1.2 to require that TOs, GOs, and DPs give their TOPs a list of transmission facilities that implement R1.2.

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide a list of the facilities associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports, to allow entities to know which facilities have protective relay settings that limit the

FERC Order 733, ¶224: Make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant sub-requirement R1.12.of anticipated overload.

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

facility's capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

R6. Each Planning Coordinator shall apply the criteria in Attachment B to an assessment conducted at least once each calendar year, with no more than 15 months between assessments, to determine which transmission Elements must comply with this standard. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Apply the criteria to transmission lines that are operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.

6.2 Apply the criteria to transmission lines operated below 100 kV and transformers with low voltage terminal connections below 100 kV, if the Regional Entity has identified either of these Element types as critical facilities for the purposes of the Compliance Registry and they are in its Planning Coordinator Area.

6.3 Maintain a list of facilities determined according to the process described in Requirement R6.

6.4 Include on the list the year studied for which criterion B4 in Attachment B first applies when a facility is added and only criterion B4 is applicable.

6.5 Provide a list of facilities 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.

> FERC Order 733, ¶237: Modify sub-requirement R3.3 to add the RE to list of entities that receive the critical facilities list.

R7. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement Requirement R1, Requirement R2, Requirement R3, Requirement R4, and Requirement R5 for each facility that is added to the Planning Coordinator's list of facilities that must comply with this standard pursuant to Requirement R6, Part 6.5 by the later of the first day of the second calendar quarter 24 months following notification by the Planning Coordinator of a facility's inclusion on such a list or the first day of the first calendar quarter of the year in which Attachment B criterion B4 first applies. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

C. Measures

M1. The 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.

M2. The 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 allows 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. The 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 they 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. The 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 they provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with a list of facilities associated with those transmission line relays. (R4)

M5. The 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 a list of the facilities associated with those relays to its Regional Entity. (R5)

M6. The Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that they used the criteria established within Attachment B to determine the facilities that must comply with this standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such facilities 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.

M7. The Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as dated spreadsheets, summaries of calculations, and study reports, that it implemented the Requirements within the specified timeframe per Requirement R7.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Entity

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 and R7 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 facilities that are critical to the reliability of the electric system 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 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. 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, Regional Entity, and Reliability Coordinator with a list of facilities 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 a list of facilities 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 which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard and met parts 6.3 through 6.5, but more than 15 months and less than 24 months lapsed between assessments. OR	The Planning Coordinator used the criteria established within Attachment B to determine which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard and met parts 6.3 through 6.5, but 24 months or more lapsed between assessments. OR	The Planning Coordinator failed to use the criteria established within Attachment B to determine which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard. OR The Planning Coordinator used the criteria established within Attachment B, at least once each

		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 which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard and met 6.3 and 6.5 but failed to include the year studied for which criterion B4 in Attachment B first applies when a facility is added and only criterion B4 is applicable (part 6.4). 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 which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard and met 6.3 and 6.4 but provided the list of facilities to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator Area within 31days and 45 days after the list was established or updated (part 6.5).	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 which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard and met 6.3 and 6.4 but provided the list of facilities to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator Area within 46 days and 60 days after list was established or updated (part 6.5).	calendar year, with no more than 15 months between assessments, to determine which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard but failed to meet parts 6.3, 6.4 and 6.5. 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 which transmission Elements in its Planning Coordinator area must comply with the standard but failed to apply the criteria to the Elements described in 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 which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard and met 6.4 and 6.5 but failed to maintain the list of facilities determined according to the process described in Requirement R6 (part 6.3). 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 which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard and met 6.3 and 6.4 but failed to provide the list of facilities 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 6.5).
R7	N/A	N/A	N/A	The Transmission Owner, Generator Owner, or Distribution Provider failed to implement Requirement R1, Requirement R2, Requirement R3, Requirement R4, and Requirement R5 for each facility that is added to the Planning Coordinator's list of facilities that must comply with this standard pursuant to Requirement R6, Part 6.5 by the later of the first day of the second calendar quarter after 24 months following notification by the Planning Coordinator of a facility's inclusion on such a list by the Planning Coordinator or the first day of the first calendar quarter of the year in which Attachment B criterion B4 first applies.

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, January 9, 2007, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/~filez/reports.html.

Version History

Version	Date	Action	Change Tracking
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	
2	November 1, 2010	Revised to address directives from Order 733	

PRC-023 — 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. Supervisory elements associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications.

FERC Order 733, ¶264: Revise section 1 of Attachment A to include supervising relay elements.

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 — Attachment B

FERC Order 733, ¶69: Specify the test that PCs must use to determine whether sub-200 kV facility is critical to reliability of the BES

Criteria

Review each applicable circuit against the criteria in this Attachment to determine the facilities that must comply with the standard.

Applicable circuits include:

- 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 below100 kV and transformers with low voltage terminals connected below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry

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

B1. Each circuit that is a monitored Element of a flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Element in the Texas Interconnection or Québec Interconnection, that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator.

B2. Each circuit that is a monitored Element of an IROL where the IROL was determined in the long-term planning horizon.

B3. Each circuit that forms a path (as agreed to by the plant owner and the Transmission Entity) to supply off-site power to nuclear plants.

B4. Each circuit identified through the following power flow analysis:

- Simulate double contingency combinations selected by engineering judgment in TPL-003 Category C3, but without manual system adjustments in between (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).

- For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading against the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.

- 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.

- The threshold for selection as a circuit that must comply with the standard will vary based on the loading duration assumed in the development of the Facility Rating.

  a. 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.

b. 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.

c. 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.

- Radial circuits serving only load are excluded.

B5. Each circuit that the Planning Coordinator may include based on other technical studies or assessments.

A. Introduction

1. Title: Transmission Relay Loadability

2. Number: PRC-023-2

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 Entities:

4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023 - Attachment A, applied to facilities defined ~~below~~in 4.2.1 through 4.2.6.

4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023- Attachment A, applied to facilities defined in 4.2.1 through 4.2.6.

4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023- Attachment A, applied according to facilities defined in 4.2.1 through 4.2.6, provided those facilities have bi-directional flow capabilities.

4.1.4 Planning Coordinators

~~4.1.~~4.2. Facilities:

~~4.1.1~~4.2.1 Transmission lines operated at 200 kV and above.

4.2.2 Transmission lines operated at 100 kV to 200 kV that the Planning Coordinator has determined are required to comply with this standard.

~~4.1.2~~4.2.3 Transmission lines operated below ~~200 kV designated by the Planning Coordinator~~ 100 kV that Regional Entities have identified as critical ~~to~~ facilities for the ~~reliability~~purposes of the ~~Bulk Electric System~~Compliance Registry and the Planning Coordinator has determined are required to comply with this standard.

FERC Order 733, ¶60: Apply an "add in" approach to sub-100 kV facilities.

~~4.1.3~~4.2.4 Transformers with low voltage terminals connected at 200 kV and above.

~~4.1.4~~4.2.5 Transformers with low voltage terminals connected ~~below~~at 100 kV to 200 kV ~~as designated by~~that the Planning Coordinator ~~as critical to the reliability of the Bulk Electric System (BES).~~has determined are required to comply with this standard.

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

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

FERC Order 733, ¶284: Remove the exceptions footnote from the "Effective Dates" section.

~~**4.4.** Planning Coordinators.~~

4.2.6 Transformers with low voltage terminals connected below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry and the Planning Coordinator has determined are required to comply with this standard.

5. Effective Dates:

~~5.1.~~ Requirement R1~~, Requirement R2, Requirement R3, Requirement R4:~~

~~**5.1.1** For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) — the beginning of~~: the first day of the first calendar quarter ~~following~~after applicable regulatory approvals~~.~~

~~5.2.~~5.1. ~~For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable~~ or in those jurisdictions where no regulatory ~~approvals.~~ approval is required, the first calendar quarter after Board of Trustees adoption, except as noted below.

~~**5.2.1** Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its Planning Coordinator pursuant to Requirement R5, Part 5.3 to comply with Requirement R1 (including all sub-requirements) for each facility that is added to the Planning Coordinator's critical facilities list determined pursuant to Requirement R5, Part 5.1.~~

~~**5.3.** Requirement R5: 18 months following applicable regulatory approvals.~~

5.1.1 For the addition to Requirement R1, criterion 10, to set transformer fault protection relays and transmission line 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, the first day of the first calendar quarter 12 months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 12 months after Board of Trustees adoption.

5.1.2 For supervisory elements as described in PRC-023 - Attachment A, section 1.6, the first day of the first calendar quarter 24 months after applicable regulatory approvals or in those jurisdictions where regulatory approval is not required, the first day of the first calendar quarter 24 months after Board of Trustees adoption.

5.2. Requirements R2 and R3: the first day of the first calendar quarter after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

5.3. Requirements R4 and R5: the first day of the first calendar quarter six months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required the first day of the first calendar quarter six months after Board of Trustees adoption.

5.4. Requirement R6: the first day of the first calendar quarter 18 months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required the first day of the first calendar quarter 18 months after Board of Trustees adoption.

5.5. Requirement R7: the first day of the first calendar quarter after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1, ~~Settings1~~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~~, and to prevent its out-of-step blocking schemes from blocking tripping for 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] [Mitigation Time Horizon: Long Term Planning]*.

~~Settings~~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, ~~Setting~~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.
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 to the 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.

FERC Order 733, ¶203: Modify sub-requirement R1.10 to verify equipment is capable of sustaining the anticipated overload associated with the fault.

10. Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer such that the protection settings do not expose the ~~limiting piece of equipment~~transformer to fault level and duration that exceeds its mechanical withstand capability and 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.

11. For transformer overload protection relays that do not comply with the loadability component of Requirement R1, ~~Setting~~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[2].

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, ~~Setting~~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 verify that its out-of-step blocking elements 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]*

FERC Order 733, ¶244: Include section 2 of Appendix A as an additional Requirement.

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

~~R2.~~R3. Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in Requirement R1, ~~Settings.~~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]*

~~R3.~~R4. Each Transmission Owner, Generator Owner, and Distribution Provider that ~~sets~~chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line ~~relays according to Requirement R1 Setting 2~~relay loadability shall provide its Planning Coordinator, Transmission Operator~~, Regional Entity~~, and Reliability Coordinator with a list of facilities 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]*

> FERC Order 733, ¶186: Modify R1.2 to require that TOs, GOs, and DPs give their TOPs a list of transmission facilities that implement R1.2.

~~R4.~~R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 ~~Setting~~criterion 12 shall provide a list of the facilities associated with those relays to its Regional Entity at least once each calendar year, with no more than 15 months between reports~~.~~, to allow entities to know which facilities have protective relay settings that limit the facility's capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

> FERC Order 733, ¶224: Make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant sub-requirement R1.12.of anticipated overload.

R6. Each Planning Coordinator shall apply the criteria in Attachment B to an assessment conducted at least once each calendar year, with no more than 15 months between assessments, to determine which ~~of~~transmission Elements must comply with this standard. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

6.1 Apply the ~~facilities (~~criteria to transmission lines that are operated ~~below~~at 100 kV to 200 kV and transformers with low voltage terminals connected ~~below 200 kV)~~ at 100 kV to 200 kV.

~~6.1~~6.2 Apply the criteria to transmission lines operated below 100 kV and transformers with low voltage terminal connections below 100 kV, if the Regional Entity has identified either of these Element types as critical facilities for the purposes of the Compliance Registry and they are in its Planning Coordinator Area ~~are critical to the reliability of the BES to identify the facilities below 200 kV that must meet Requirement R1 to prevent cascading when protective relay settings limit transmission loadability. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]~~.

~~**5.2** The Planning Coordinator shall have a process to use the criteria established within Attachment B to determine the facilities that are critical to the reliability of the Bulk Electric System.~~

6.3 ~~Each Planning Coordinator shall maintain a current~~Maintain a list of facilities determined according to the process described in Requirement ~~R5 Part 5.1~~R6.

6.4 ~~Each Planning Coordinator shall provide~~Include on the list the year studied for which criterion B4 in Attachment B first applies when a facility is added and only criterion B4 is applicable.

~~6.4~~6.5 Provide a list of facilities to ~~its~~all Regional ~~Entity~~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.

FERC Order 733, ¶237: Modify sub-requirement R3.3 to add the RE to list of entities that receive the critical facilities list.

R7. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement Requirement R1, Requirement R2, Requirement R3, Requirement R4, and Requirement R5 for each facility that is added to the Planning Coordinator's list of facilities that must comply with this standard pursuant to Requirement R6, Part 6.5 by the later of the first day of the second calendar quarter 24 months following notification by the Planning Coordinator of a facility's inclusion on such a list or the first day of the first calendar quarter of the year in which Attachment B criterion B4 first applies. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

C. Measures

M1. The 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.

M2. The 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 allows 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. The 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 they 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. The 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 they provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with a list of facilities associated with those transmission line relays. (R4)

M5. The 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 a list of the facilities associated with those relays to its Regional Entity. (R5)

M6. The Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that they used the criteria established within Attachment B to determine the facilities that must comply with this standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such facilities 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.

M7. The Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as dated spreadsheets, summaries of calculations, and study reports, that it implemented the Requirements within the specified timeframe per Requirement R7.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Entity

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 and R7 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 facilities that are critical to the reliability of the electric system 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 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. 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, Regional Entity, and Reliability Coordinator with a list of facilities 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 a list of facilities 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 which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard and met parts 6.3 through 6.5, but more than 15 months and less than 24 months lapsed between assessments. OR	The Planning Coordinator used the criteria established within Attachment B to determine which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard and met parts 6.3 through 6.5, but 24 months or more lapsed between assessments. OR	The Planning Coordinator failed to use the criteria established within Attachment B to determine which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard. OR The Planning Coordinator used the criteria established within Attachment B, at least once each

		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 which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard and met 6.3 and 6.5 but failed to include the year studied for which criterion B4 in Attachment B first applies when a facility is added and only criterion B4 is applicable (part 6.4). 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 which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard and met 6.3 and 6.4 but provided the list of facilities to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator Area within 31days and 45 days after the list was established or updated (part 6.5).	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 which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard and met 6.3 and 6.4 but provided the list of facilities to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator Area within 46 days and 60 days after list was established or updated (part 6.5).	calendar year, with no more than 15 months between assessments, to determine which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard but failed to meet parts 6.3, 6.4 and 6.5. 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 which transmission Elements in its Planning Coordinator area must comply with the standard but failed to apply the criteria to the Elements described in 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 which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard and met 6.4 and 6.5 but failed to maintain the list of facilities determined according to the process described in Requirement R6 (part 6.3). 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 which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard and met 6.3 and 6.4 but failed to provide the list of facilities 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 6.5).
R7	N/A	N/A	N/A	The Transmission Owner, Generator Owner, or Distribution Provider failed to implement Requirement R1, Requirement R2, Requirement R3, Requirement R4, and Requirement R5 for each facility that is added to the Planning Coordinator's list of facilities that must comply with this standard pursuant to Requirement R6, Part 6.5 by the later of the first day of the second calendar quarter after 24 months following notification by the Planning Coordinator of a facility's inclusion on such a list by the Planning Coordinator or the first day of the first calendar quarter of the year in which Attachment B criterion B4 first applies.

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, January 9, 2007, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/~filez/reports.html.

Version History

Version	Date	Action	Change Tracking
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	
2	November 1, 2010	Revised to address directives from Order 733	

PRC-023 — 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.** Protective functions that supervise operation of other protective functions in 1.1 through 1.5.~~

1.6. Supervisory elements associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications.

FERC Order 733, ¶264: Revise section 1 of Attachment A to include supervising relay elements.

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 — Attachment B

FERC Order 733, ¶69: Specify the test that PCs must use to determine whether sub-200 kV facility is critical to reliability of the BES

Criteria

Review each applicable circuit against the criteria in this Attachment to determine the facilities that must comply with the standard.

Applicable circuits include:

- 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 below100 kV and transformers with low voltage terminals connected below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry

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

B1. Each circuit that is a monitored Element of a flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Element in the Texas Interconnection or Québec Interconnection, that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator.

B2. Each circuit that is a monitored Element of an IROL where the IROL was determined in the long-term planning horizon.

B3. Each circuit that forms a path (as agreed to by the plant owner and the Transmission Entity) to supply off-site power to nuclear plants.

B4. Each circuit identified through the following power flow analysis:

- Simulate double contingency combinations selected by engineering judgment in TPL-003 Category C3, but without manual system adjustments in between (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
- For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading against the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
- 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.
- The threshold for selection as a circuit that must comply with the standard will vary based on the loading duration assumed in the development of the Facility Rating.
  a. 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.

b. 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.

c. 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.

- Radial circuits serving only load are excluded.

B5. Each circuit that the Planning Coordinator may include based on other technical studies or assessments.

A. Introduction

1. **Title: Transmission Relay Loadability**

2. **Number:** PRC-023-~~1~~2

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~~Faults.

4. **Applicability:**

4.1. Functional Entities:

4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023 - Attachment A, applied to facilities defined ~~below~~in 4.2.1 through 4.2.6.

4.1.2 Generator Owners with load-responsive phase protection systems as described in PRC-023- Attachment A, applied to facilities defined in 4.2.1 through 4.2.6.

4.1.3 Distribution Providers with load-responsive phase protection systems as described in PRC-023- Attachment A, applied according to facilities defined in 4.2.1 through 4.2.6, provided those facilities have bi-directional flow capabilities.

4.1.4 Planning Coordinators

~~4.1.~~4.2. Facilities:

~~4.1.1~~4.2.1 Transmission lines operated at 200 kV and above.

4.2.2 Transmission lines operated at 100 kV to 200 kV ~~as designated by~~that the Planning Coordinator has determined are required to comply with this standard.

~~4.1.2~~4.2.3 Transmission lines operated below 100 kV that Regional Entities have identified as critical ~~to~~ facilities for the ~~reliability~~purposes of the ~~Bulk Electric System.~~Compliance Registry and the Planning Coordinator has determined are required to comply with this standard.

~~4.1.3~~4.2.4 Transformers with low voltage terminals connected at 200 kV and above.

~~4.1.4~~4.2.5 Transformers with low voltage terminals connected at 100 kV to 200 kV ~~as designated by~~that the Planning Coordinator ~~as critical~~has determined are required to ~~the reliability of the Bulk Electric System~~comply with this standard.

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

~~4.3. Distribution Providers with load-responsive phase protection systems as described in Attachment A, applied according to facilities defined in 4.1.1 through 4.1.4., provided~~low voltage terminals connected below 100 kV that ~~those facilities~~Regional Entities have ~~bi-directional flow capabilities.~~

~~4.4. Planning Coordinators.~~

FERC Order 733, ¶60: Apply an "add in" approach to sub-100 kV facilities.

FERC Order 733, ¶284: Remove the exceptions footnote from the "Effective Dates" section.

~~**5. Effective Dates[1]:**~~

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

~~**5.1.1** For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) — the beginning of the first calendar quarter following applicable regulatory approvals.~~

~~**5.1.2** For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals.~~

~~5.1.3~~4.2.6 ~~Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its~~ identified as critical facilities for the purposes of the Compliance Registry and the Planning Coordinator ~~pursuant to R3.3~~has determined are required to comply with ~~R1 (including all sub-requirements) for each facility that is added to the Planning Coordinator's critical facilities list determined pursuant to R3.1~~this standard.

5. Effective Dates:

5.1. Requirement ~~3: 18 months following~~R1: the first day of the first calendar quarter after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first calendar quarter after Board of Trustees adoption, except as noted below.

5.1.1 For the addition to Requirement R1, criterion 10, to set transformer fault protection relays and transmission line 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, the first day of the first calendar quarter 12 months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 12 months after Board of Trustees adoption.

5.1.2 For supervisory elements as described in PRC-023 - Attachment A, section 1.6, the first day of the first calendar quarter 24 months after applicable regulatory approvals or in those jurisdictions where regulatory approval is not required, the first day of the first calendar quarter 24 months after Board of Trustees adoption.

5.2. Requirements R2 and R3: the first day of the first calendar quarter after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

5.3. Requirements R4 and R5: the first day of the first calendar quarter six months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required the first day of the first calendar quarter six months after Board of Trustees adoption.

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

5.4. Requirement R6: the first day of the first calendar quarter 18 months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required the first day of the first calendar quarter 18 months after Board of Trustees adoption.

~~5.2.~~5.5. Requirement R7: the first day of the first calendar quarter after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

B. Requirements

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

Criteria:

~~a.~~**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).

~~b.~~**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).

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

- ~~**R1.**~~ An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line.
- ~~**R2.**~~ 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.

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

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

~~e.~~**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).

[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.

~~f.~~**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.

~~g.~~**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.

~~h.~~**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.

~~i.~~**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.

FERC Order 733, ¶203: Modify sub-requirement R1.10 to verify equipment is capable of sustaining the anticipated overload associated with the fault.

~~j.~~**10.** Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer ~~so that they~~such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability and so that the relays do not operate at or below the greater of:

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

~~k.~~**11.** For transformer overload protection relays that do not comply with ~~R1.~~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~~. The protection must allow this overload~~, for at least 15 minutes to ~~allow~~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~~. The setting should be~~ set no less than 100° C for the top oil ~~or~~temperature or no less than 140° C for the winding hot spot temperature[3].

~~l.~~**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:

~~1.~~a. Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.

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

~~2.~~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.

~~3.~~c. Include a relay setting component of 87% of the current calculated in Requirement R1~~.~~, criterion 12~~.2~~ in the Facility Rating determination for the circuit.

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

R2. ~~The~~Each Transmission Owner, Generator Owner, ~~or~~and Distribution Provider shall verify that its out-of-step blocking elements 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]*

FERC Order 733, ¶244: Include section 2 of Appendix A as an additional Requirement.

~~**R2.**~~**R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in ~~R1.~~Requirement R1, criterion 6, ~~R1.~~7, ~~R1.~~8, ~~R1.~~9, ~~R1.~~12, or ~~R1.~~13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

R4. ~~The Planning Coordinator shall determine which of the facilities (transmission lines~~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 a list of facilities 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]*

FERC Order 733, ¶186: Modify R1.2 to require that TOs, GOs, and DPs give their TOPs a list of transmission facilities that implement R1.2.

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

FERC Order 733, ¶224: Make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant sub-requirement R1.12.of anticipated overload.

R6. Each Planning Coordinator shall apply the criteria in Attachment B to an assessment conducted at least once each calendar year, with no more than 15 months between assessments, to determine which transmission Elements must comply with this standard. The Planning Coordinator shall: *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

~~o~~**6.1** Apply the criteria to transmission lines that are operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV~~) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]~~.

~~**R2.1.** The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System.~~

- ~~This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.~~

6.2 ~~The Planning Coordinator shall maintain a current~~ Apply the criteria to transmission lines operated below 100 kV and transformers with low voltage terminal connections below 100 kV, if the Regional Entity has identified either of these Element types as critical facilities for the purposes of the Compliance Registry and they are in its Planning Coordinator Area.

~~o~~6.3 Maintain a list of facilities determined according to the process described in ~~R3.1~~Requirement R6.

> FERC Order 733, ¶237: Modify sub-requirement R3.3 to add the RE to list of entities that receive the critical facilities list.

6.4 ~~The Planning Coordinator shall provide~~Include on the list the year studied for which criterion B4 in Attachment B first applies when a facility is added and only criterion B4 is applicable.

6.5 Provide a list of facilities to ~~its~~all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within ~~30~~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.

~~R3.~~R7. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement Requirement R1, Requirement R2, Requirement R3, Requirement R4, and Requirement R5 for each facility that is added to the ~~list.~~ Planning Coordinator's list of facilities that must comply with this standard pursuant to Requirement R6, Part 6.5 by the later of the first day of the second calendar quarter 24 months following notification by the Planning Coordinator of a facility's inclusion on such a list or the first day of the first calendar quarter of the year in which Attachment B criterion B4 first applies. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*

C. Measures

M1. The Transmission Owner, Generator Owner, and Distribution Provider shall ~~each~~ have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays ~~are~~is set according to one of the criteria in ~~R1.~~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.

~~M1.~~M2. The 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 allows tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1.~~13.~~ ~~(R1~~ (R2)

~~M2.~~M3. The Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to ~~the criteria in~~Requirement R1~~.~~, criterion 6, ~~R1.~~7, ~~R1.~~8, ~~R1.~~9, ~~R1.~~12, or ~~R.~~13 shall have evidence such as Facility Rating spreadsheets or Facility Rating database to show that they 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. (~~R2~~R3)

M4. The 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 they provided its Planning Coordinator~~ shall have a documented process for the determination of~~ , Transmission Operator, and Reliability Coordinator with a list of facilities ~~as described in R3.~~ associated with those transmission line relays. (R4)

M5. The 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 a list of the facilities associated with those relays to its Regional Entity. (R5)

~~M3.~~**M6.** The Planning Coordinator shall have ~~a current list of such facilities and shall have~~ evidence such as power flow results, calculation summaries, or study reports that ~~it provided~~they used the ~~list to~~ criteria established within Attachment B to determine the ~~approriate~~facilities that must comply with this standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such facilities and shall have evidence such as dated correspondence that it provided the list to the Regional Entities, Reliability Coordinators, Transmission ~~Operators~~Owners, Generator ~~Operators~~Owners, and Distribution Providers~~. (R3)~~ within its Planning Coordinator Area.

M7. The Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as dated spreadsheets, summaries of calculations, and study reports, that it implemented the Requirements within the specified timeframe per Requirement R7.

D. Compliance

1. Compliance Monitoring Process

~~3.1.~~1.1. Compliance Monitoring Responsibility

~~**3.1.1** Compliance Enforcement Authority~~

~~**3.2. Compliance Monitoring Period and Reset Time Frame**~~

~~One calendar year.~~

Regional Entity

~~3.3.~~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 and R7 for three calendar years.

The Planning Coordinator shall retain documentation of the most recent review process required in ~~R3~~R6. The Planning Coordinator shall retain the most recent list of facilities that are critical to the reliability of the electric system determined per ~~R3~~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 shall ~~retain its compliance documentation for three years~~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

~~3.4.~~1.4. Additional Compliance Information

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

None.

~~4.~~2. Violation Severity Levels:

~~R#~~Requirement	Lower	Moderate	High	Severe
R1	N/A	~~Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but evidence is incomplete or incorrect for one or more of the subrequirements.~~ N/A	N/A	~~Relay settings do not comply with any of the sub requirements R1.1 through R1.13~~ ~~OR~~ ~~Evidence does not exist to support that relay settings comply with one of the criteria in subrequirements R1.1 through R1.13.~~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.
~~R2~~R3	~~Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2.~~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. 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, Regional Entity, and Reliability Coordinator with a list of facilities 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 a list of facilities 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.
~~R3~~R6	N/A	~~Provided~~The Planning Coordinator used the criteria	~~Provided~~The Planning Coordinator used the criteria	~~Does not have a process in place to determine facilities~~

		established within Attachment B to determine which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard and met parts 6.3 through 6.5, 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 which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard and met 6.3 and 6.5 but failed to include the year studied for which criterion B4 in Attachment B first applies when a facility is added and only criterion B4 is applicable (part 6.4). 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 which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard and met 6.3 and 6.4 but provided the list of facilities ~~critical to the reliability of the~~	established within Attachment B to determine which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard and met parts 6.3 through 6.5, 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 which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard and met 6.3 and 6.4 but provided the list of facilities ~~critical to the reliability of the Bulk Electric System to the appropriate~~to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers ~~between~~within its Planning Coordinator Area within 46 days and 60 days after list was established or updated~~.~~ (part 6.5).	~~that are critical to the reliability of the Bulk Electric System.~~ The Planning Coordinator failed to use the criteria established within Attachment B to determine which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard. OR ~~Does not maintain a current list of facilities critical to the reliability of the Bulk Electric System,~~ ~~OR~~ ~~Did not~~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 which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard but failed to meet parts 6.3, 6.4 and 6.5. 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 which transmission Elements in its Planning Coordinator area must comply with the standard but failed to apply the criteria to the Elements

		~~Bulk Electric System to the appropriate~~to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers ~~between 31 days~~within its Planning Coordinator Area within 31days and 45 days after the list was established or updated~~.~~ (part 6.5).		described in 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 which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard and met 6.4 and 6.5 but failed to maintain the list of facilities determined according to the process described in Requirement R6 (part 6.3). 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 which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard and met 6.3 and 6.4 but failed to provide the list of facilities ~~critical to the reliability of the Bulk Electric System to the appropriate~~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 6.5).

R7	N/A	N/A	N/A	The Transmission Owner, Generator Owner, or Distribution Provider failed to implement Requirement R1, Requirement R2, Requirement R3, Requirement R4, and Requirement R5 for each facility that is added to the Planning Coordinator's list of facilities that must comply with this standard pursuant to Requirement R6, Part 6.5 by the later of the first day of the second calendar quarter after 24 months following notification by the Planning Coordinator of a facility's inclusion on such a list by the Planning Coordinator or the first day of the first calendar quarter of the year in which Attachment B criterion B4 first applies.

E. Regional Differences

None

F. Supplemental Technical Reference Document

~~1.~~3. The following document is an explanatory supplement to the standard. It provides the technical rationale underlying the requirements in this standard. The reference document contains methodology examples for illustration purposes it does not preclude other technically comparable methodologies

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

Version History

Version	Date	Action	Change Tracking
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	
2	November 1, 2010	Revised to address directives from Order 733	

PRC-023 — Attachment A

~~R1.~~1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:

~~4.1.~~1.1. Phase distance.

~~4.2.~~1.2. Out-of-step tripping.

~~4.3.~~1.3. Switch-on-to-fault.

~~4.4.~~1.4. Overcurrent relays.

~~4.5.~~1.5. Communications aided protection schemes including but not limited to:

~~4.5.1~~1.5.1 Permissive overreach transfer trip (POTT).

~~4.5.2~~1.5.2 Permissive under-reach transfer trip (PUTT).

~~4.5.3~~1.5.3 Directional comparison blocking (DCB).

~~4.5.4~~1.5.4 Directional comparison unblocking (DCUB).

FERC Order 733, ¶264: Revise section 1 of Attachment A to include supervising relay elements.

~~5. This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.~~

1.6. Supervisory elements associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications.

~~R2.~~2. The following protection systems are excluded from requirements of this standard:

~~5.1.~~2.1. Relay elements that are only enabled when other relays or associated systems fail. For example:

~~1.3.1~~• Overcurrent elements that are only enabled during loss of potential conditions.

~~1.3.2~~• Elements that are only enabled during a loss of communications~~.~~ except as noted in section 1.6

~~5.2.~~2.2. Protection systems intended for the detection of ground fault conditions.

~~5.3.~~2.3. Protection systems intended for protection during stable power swings.

~~5.4.~~2.4. Generator protection relays that are susceptible to load.

~~5.5.~~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.

~~5.6.~~2.6. Protection systems that are designed only to respond in time periods which allow ~~operators~~ 15 minutes or greater to respond to overload conditions.

~~5.7.~~2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

~~5.8.~~2.8. Relay elements associated with ~~DC~~dc lines.

~~5.9.~~2.9. Relay elements associated with ~~DC~~dc converter transformers.

PRC-023 — Attachment B

FERC Order 733, ¶69: Specify the test that PC's must use to determine whether sub-200 kV facility is critical to reliability of the BES

Criteria

Review each applicable circuit against the criteria in this Attachment to determine the facilities that must comply with the standard.

Applicable circuits include:

- 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 below100 kV and transformers with low voltage terminals connected below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry

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

B1. Each circuit that is a monitored Element of a flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Element in the Texas Interconnection or Québec Interconnection, that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator.

B2. Each circuit that is a monitored Element of an IROL where the IROL was determined in the long-term planning horizon.

B3. Each circuit that forms a path (as agreed to by the plant owner and the Transmission Entity) to supply off-site power to nuclear plants.

B4. Each circuit identified through the following power flow analysis:

- Simulate double contingency combinations selected by engineering judgment in TPL-003 Category C3, but without manual system adjustments in between (reflects a situation where a System Operator may not have time between the two contingencies to make appropriate system adjustments).
- For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading against the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.
- 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.
- The threshold for selection as a circuit that must comply with the standard will vary based on the loading duration assumed in the development of the Facility Rating.

  a. 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.

b. 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.

c. 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.

- Radial circuits serving only load are excluded.

B5. Each circuit that the Planning Coordinator may include based on other technical studies or assessments.

Standard Authorization Request Form

Title of Proposed Standard	Relay Loadability Order 733
Request Date	8/5/2010
SC Approval Date	8/12/2010
Revised Date	11/1/2010

SAR Requester Information		**SAR Type** (*Check a box for each one that applies.*)	
Name	Stephanie Monzon	☒	New Standard
Primary Contact	Stephanie.monzon@nerc.net	☒	Revision to existing Standard
Telephone Fax	610-608-8084	☐	Withdrawal of existing Standard
E-mail	Stephanie.monzon@nerc.net	☐	Urgent Action

Purpose As the ERO, NERC must address all directives in Orders issued by FERC. On March 18, 2010 FERC issued Order No. 733 which approved Reliability Standard PRC-023-1 – Transmission Relay Loadability, and also directed NERC, as the Electric Reliability Organization ("ERO"), to develop certain modifications to the PRC-023-1 standard through its Reliability Standards development process, to be completed by specific deadlines. Attachment 1 to the SAR contains the directives and associated deadlines. The Order also directed development of two new Reliability Standards to address issues related to generator relay loadability and the operation of protective relays due to power swings. The standards-related directives in Order 733 are aimed at closing some reliability-related gaps in the scope of PRC-023-1.

Industry Need

FERC directed NERC to develop modifications related to Relay Loadability by specific deadlines in Order No. 733. Attachment 1 to the SAR contains the directives and associated deadlines.

<u>PRC-023-1 Directed Modifications</u>
The Commission directed a number of changes to the approved standard including a test to be applied by Planning Coordinators to determine applicability to elements operated at less than 200 kV. This test will be included in PRC-023-1 either in the form of a Requirement or as an attachment to the standard.

<u>Generator Step-up and Auxiliary Transformers</u>
The Commission directed the ERO to develop a new Reliability Standard addressing generator relay loadability, with its own individual timeline, and not a revision to an existing Standard.

<u>Protective Relays Operating Unnecessarily Due to Stable Power Swings</u>
The Commission observed that PRC-023-1 does not address stable power swings, and pointed out that currently available protection applications and relays, such as pilot wire differential, phase comparison and blinder-blocking applications and relays, and impedance relays with non-circular operating characteristics, are demonstrably less susceptible to operating unnecessarily because of stable power swings. Given the availability of alternatives, the Commission stated that the use of protective relay systems that cannot differentiate between faults and stable power swings constitutes miscoordination of the protection system and is inconsistent with entities' obligations under existing Reliability Standards.

In this Final Rule the Commission decided not to direct the ERO to modify PRC-023-1 to address stable power swings. However, because both NERC and the U.S.-Canada Power System Outage Task Force have identified undesirable relay operation due to stable power swings as a reliability issue, the Commission directed the ERO to develop a Reliability Standard that requires use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases out protective relays that cannot meet this requirement.

Brief Description
This SAR's scope includes three standard development phases to address the standards-related directives in Order No. 733 directives. Phase I is focused on making the specific modifications to PRC-023-1 that were identified in the order; Phase II is focused on developing a new standard to address generator relay loadability; and Phase III is focused on developing requirements that address protective relay operations due to power swings.

Detailed Description

Phase I: Develop modifications to PRC-023-1- Transmission Relay Loadability by March 18, 2011 to address the following directives from Order 733:

- p. 60 . . . modify PRC-023-1 to apply an "add in" approach to sub-100 kV facilities that are owned or operated by currently-Registered Entities or entities that become Registered Entities in the future, and are associated with a facility that is included on a critical facilities list defined by the Regional Entity.
- p. 69 . . . modify Requirement R3 of the Reliability Standard to specify the test that planning coordinators must use to determine whether a sub-200 kV facility is critical to the reliability of the Bulk-Power System.
- p 162 . . . consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings.
- p. 186 . . . require that transmission owners, generator owners, and distribution providers give their transmission operators a list of transmission facilities that implement sub-requirement R1.2.
- p. 203 . . . modify sub-requirement R1.10 so that it requires entities to verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with the fault.
- P. 224… direct the ERO to document, subject to audit by the Commission, and to make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant sub-requirement R1.12.
- p. 237 . . . modify the Reliability Standard to add the Regional Entity to the list of entities that receive the critical facilities list. [sub-requirement R3.3]
- p. 244 . . . include section 2 of Attachment A in the modified Reliability Standard as an additional Requirement with the appropriate violation risk factor and violation severity level.
- p. 264 . . . revise section 1 of Attachment A to include supervising relay elements on the list of relays and protection systems that are specifically subject to the Reliability Standard.
- p. 283 . . . modify the Reliability Standard to include an implementation plan for sub-100 kV facilities.
- p. 284 . . . remove the exceptions footnote from the "Effective Dates" section.

In Phase I of the project, the NERC Relay Loadability standard drafting team will either modify the PRC-023-1 Reliability Standard to incorporate the directed modifications or will propose equally efficient and effective alternative approaches that address the Commission's reliability-related concerns. *(In parallel with this effort, NERC plans to convene a panel of industry subject matter experts to develop a straw man proposal for the test Planning Coordinators must use to identify sub-200 kV facilities that are critical to the reliability of the Bulk Power System. The panel will collect industry feedback on the straw man test using the current standards development process that will be incorporated into Requirement R3 of PRC-023-1 by the Standard Drafting Team.)*

Phase II: Develop a new Standard Addressing Generator Relay Loadability
In Phase II of the project, a new Reliability Standard will be developed by the end of 2012 to address the subject of generator relay loadability in support of NERC's filing indicating it would develop such a standard and to address the following directive from Order No. 733:

- p. 108 . . . consider the PSEG Companies' suggestion in developing a Reliability Standard that addresses generator relay loadability.

As indicated in NERC's Order No. 733 clarification and rehearing request, NERC believes adding additional requirements to the PRC-023 standard in addition to developing a new Reliability Standard to address generator relay loadability could lead to confusion over applicability and the possibility of conflicting requirements. Therefore, NERC proposed in its clarification and rehearing request to address the issue of generator relay loadability in a new Reliability Standard, separate and distinct from the PRC-023 Reliability Standard, which is intended to address relays that protect transmission elements. Subject to the Commission's response to NERC's pending clarification and rehearing request, NERC plans to address generator relay loadability in a new Reliability Standard for applications where the relays are set with a shorter reach to protect the generator and the generator step-up transformer, and for applications where the relays are set with a longer reach to provide backup protection for transmission system faults. The standard drafting team will use relevant sections of the NERC technical reference document, Power Plant and Transmission System Protection Coordination Section 3.1 and Appendix E to develop the requirements by which generator relay loadability will be assessed.

<u>Phase III: Development of a New Standard Addressing the Issue of Protective Relay Operations Due To Power Swings</u>
In Phase III of the project, a new Reliability Standard will be developed to address the subject of protective relay operations due to power swings to address the following directive from Order No. 733 by the end of 2014:

- p. 150 - develop a Reliability Standard that requires the use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Assurer	Monitors and evaluates the activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.
☒	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
PRC-023-1	Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability, and directed NERC, as the Electric Reliability Organization (“ERO”), to develop certain modifications to the PRC-023-1 standard through its Reliability Standards development process, to be completed by specific deadlines.
New Reliability Standard	Development of a New Standard Addressing Generator Relay Loadability
New Reliability Standard	Development of a New Standard Addressing the Issue of Protective Relay Operations Due To Power Swings

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Attachment 1 - Order No. 733 – Action Plan and Timetable

Note that the scope of the SAR is limited to addressing the directives highlighted in the table below.

Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability, and directed NERC, as the Electric Reliability Organization ("ERO"), to develop certain modifications to the PRC-023-1 standard through its Reliability Standards development process, to be completed by specific deadlines and directed NERC to develop requirements to address issues related to Relay Loadability. The Order also directed development of two new Reliability Standards to address issues related to generator relay loadability and the operation of protective relays due to power swings. The following table lists the FERC directives in Order No. 733 and for each directive associates it with a project phase. Note that some of the tasks within each phase will be managed by NERC staff, not the standard drafting team.

Paragraph	Text	Project Phase/ Timeline
60	With respect to sub-100 kV facilities, we adopt the NOPR proposal and direct the ERO to modify PRC-023-1 to apply an "add in" approach to sub-100 kV facilities that are owned or operated by currently-Registered Entities or entities that become Registered Entities in the future, and are associated with a facility that is included on a critical facilities list defined by the Regional Entity. We also direct that additions to the Regional Entities' critical facility list be tested for their applicability to PRC-023-1 and made subject to the Reliability Standard as appropriate.	Phase I -- by March 18, 2011
69	Finally, pursuant to section 215(d)(5) of the FPA, we direct the ERO to modify Requirement R3 of the Reliability Standard to specify the test that planning coordinators must use to determine whether a sub-200 kV facility is critical to the reliability of the Bulk-Power System. We direct the ERO to file its test, and the results of applying the test to a representative sample of utilities from each of the three Interconnections, for Commission approval no later than one year from the date of this Final Rule.	Phase I -- Note NERC's pending request for rehearing filed on April 19, 2010 regarding this directive.
97	Finally, commenters argue that there should be some mechanism for entities to challenge criticality determinations. We agree that such a mechanism is appropriate and direct the ERO to develop an appeals process (or point to a process in its existing procedures) and submit it to the Commission no later than one year after the date of this Final Rule.	Phase I – by March 18, 2011
105	In light of the ERO's statement that within two years it expects to submit to the Commission a proposed Reliability Standard addressing generator relay loadability, we direct the ERO to submit to the Commission an updated and specific timeline explaining when it expects to develop and submit this proposed Standard.	Phase II – by the end of 2012
108	Finally, the PSEG Companies suggest that the ERO consider whether a generic rating percentage can be established for generator step-up transformers and, if so, determine that percentage. Although we do not adopt the NOPR proposal, we encourage the ERO to consider the PSEG Companies' suggestion in developing a Reliability Standard that addresses generator relay loadability.	Phase II – by the end of 2012
150	However, because both NERC and the Task Force have identified undesirable relay operation due to stable power swings as a reliability issue, we direct the ERO to develop a Reliability Standard that requires the use of protective relay systems that can differentiate between faults and stable power swings and,	Phase III – by the end of 2014

Attachment 1 - Order No. 733 – Action Plan and Timetable

Paragraph	Text	Project Phase/ Timeline
	when necessary, phases out protective relay systems that cannot meet this requirement. We also direct the ERO to file a report no later than 120 days of this Final Rule addressing the issue of protective relay operation due to power swings. The report should include an action plan and timeline that explains how and when the ERO intends to address this issue through its Reliability Standards development process.	
162	We agree with the PSEG Companies and direct the ERO to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings.	Phase I – by March 18, 2011
186	However, we will adopt the NOPR proposal to direct the ERO to modify PRC-023-1 to require that transmission owners, generator owners, and distribution providers give their transmission operators a list of transmission facilities that implement sub-requirement R1.2.	Phase I – by March 18, 2011
203	We adopt the NOPR proposal and direct the ERO to modify sub-requirement R1.10 so that it requires entities to verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with the fault.	Phase I – by March 18, 2011
224	While we are not adopting the NOPR proposal, we direct the ERO to document, subject to audit by the Commission, and to make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant sub-requirement R1.12.	Phase I – by March 18, 2011
237	We adopt the NOPR proposal and direct the ERO to modify the Reliability Standard to add the Regional Entity to the list of entities that receive the critical facilities list. [sub-requirement R3.3]	Phase I – by March 18, 2011
244	We adopt the NOPR proposal and direct the ERO to include section 2 of Attachment A in the modified Reliability Standard as an additional Requirement with the appropriate violation risk factor and violation severity level.	Phase I – by March 18, 2011
264	After further consideration, and in light of the comments, we will not direct the ERO to remove any exclusion from section 3, except for the exclusion of supervising relay elements in section 3.1. Consequently, we direct the ERO to revise section 1 of Attachment A to include supervising relay elements on the list of relays and protection systems that are specifically subject to the Reliability Standard.	Phase I – by March 18, 2011
283	Additionally, in light of our directive to the ERO to expand the Reliability Standard's scope to include sub-100 kV facilities that Regional Entities have already identified as necessary to the reliability of the Bulk-Power System through inclusion in the Compliance Registry, we direct the ERO to modify the Reliability Standard to include an implementation plan for sub-100 kV facilities.	Phase I – by March 18, 2011

Attachment 1 - Order No. 733 – Action Plan and Timetable

Paragraph	Text	Project Phase/ Timeline
284	We also direct the ERO to remove the exceptions footnote from the “Effective Dates” section.	Phase I – by March 18, 2011
297	Finally, we direct the ERO to assign a “high” violation risk factor to Requirement R3.	Filed with the Commission on April 19, 2010
308	Consequently, we direct the ERO to assign a single violation severity level of “severe” for violations of Requirement R1.	Filed with the Commission on April 19, 2010
310	Accordingly, we direct the ERO to change the violation severity level assigned to Requirement R2 from “lower” to “severe” to be consistent with Guideline 2a.	Filed with the Commission on April 19, 2010
311	Finally, we direct the ERO to assign a “severe” violation severity level to Requirement R3.	Filed with the Commission on April 19, 2010

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standard Authorization Request Form

Title of Proposed Standard	Relay Loadability Order 733
Request Date	8/5/2010
SC Approval Date	8/12/2010
Revised Date	11/1/2010

SAR Requester Information		**SAR Type** (*Check a box for each one that applies.*)	
Name	Stephanie Monzon	☒	New Standard
Primary Contact	Stephanie.monzon@nerc.net	☒	Revision to existing Standard
Telephone Fax	610-608-8084	☐	Withdrawal of existing Standard
E-mail	Stephanie.monzon@nerc.net	☐	Urgent Action

Purpose As the ERO, NERC must address all directives in Orders issued by FERC. On March 18, 2010 FERC issued Order No. 733 which approved Reliability Standard PRC-023-1 – Transmission Relay Loadability, and also directed NERC, as the Electric Reliability Organization (“ERO”), to develop certain modifications to the PRC-023-1 standard through its Reliability Standards development process, to be completed by specific deadlines. Attachment 1 to the SAR contains the directives and associated deadlines. The Order also directed development of two new Reliability Standards to address issues related to generator relay loadability and the operation of protective relays due to power swings. The standards-related directives in Order 733 are aimed at closing some reliability-related gaps in the scope of PRC-023-1.

Industry Need

FERC directed NERC to develop modifications related to Relay Loadability by specific deadlines in Order No. 733. Attachment 1 to the SAR contains the directives and associated deadlines.

<u>PRC-023-1 Directed Modifications</u>
The Commission directed a number of changes to the approved standard including a test to be applied by Planning Coordinators to determine applicability to elements operated at less than 200 kV. This test will be included in PRC-023-1 either in the form of a Requirement or as an attachment to the standard.

<u>Generator Step-up and Auxiliary Transformers</u>
The Commission directed the ERO to develop a new Reliability Standard addressing generator relay loadability, with its own individual timeline, and not a revision to an existing Standard.

<u>Protective Relays Operating Unnecessarily Due to Stable Power Swings</u>
The Commission observed that PRC-023-1 does not address stable power swings, and pointed out that currently available protection applications and relays, such as pilot wire differential, phase comparison and blinder-blocking applications and relays, and impedance relays with non-circular operating characteristics, are demonstrably less susceptible to operating unnecessarily because of stable power swings. Given the availability of alternatives, the Commission stated that the use of protective relay systems that cannot differentiate between faults and stable power swings constitutes miscoordination of the protection system and is inconsistent with entities’ obligations under existing Reliability Standards.

In this Final Rule the Commission decided not to direct the ERO to modify PRC-023-1 to address stable power swings. However, because both NERC and the U.S.-Canada Power System Outage Task Force have identified undesirable relay operation due to stable power swings as a reliability issue, the Commission directed the ERO to develop a Reliability Standard that requires use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases out protective relays that cannot meet this requirement.

Brief Description
This SAR’s scope includes three standard development phases to address the standards-related directives in Order No. 733 directives. Phase I is focused on making the specific modifications to PRC-023-1 that were identified in the order; Phase II is focused on developing a new standard to address generator relay loadability; and Phase III is focused on developing requirements that address protective relay operations due to power swings.

Detailed Description

Phase I: Develop modifications to PRC-023-1- Transmission Relay Loadability by March 18, 2011 to address the following directives from Order 733:

- p. 60 . . . modify PRC-023-1 to apply an "add in" approach to sub-100 kV facilities that are owned or operated by currently-Registered Entities or entities that become Registered Entities in the future, and are associated with a facility that is included on a critical facilities list defined by the Regional Entity.
- p. 69 . . . modify Requirement R3 of the Reliability Standard to specify the test that planning coordinators must use to determine whether a sub-200 kV facility is critical to the reliability of the Bulk-Power System.
- p 162 . . . consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings.
- p. 186 . . . require that transmission owners, generator owners, and distribution providers give their transmission operators a list of transmission facilities that implement sub-requirement R1.2.
- p. 203 . . . modify sub-requirement R1.10 so that it requires entities to verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with the fault.
- P. 224… direct the ERO to document, subject to audit by the Commission, and to make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant sub-requirement R1.12.
- p. 237 . . . modify the Reliability Standard to add the Regional Entity to the list of entities that receive the critical facilities list. [sub-requirement R3.3]
- p. 244 . . . include section 2 of Attachment A in the modified Reliability Standard as an additional Requirement with the appropriate violation risk factor and violation severity level.
- p. 264 . . . revise section 1 of Attachment A to include supervising relay elements on the list of relays and protection systems that are specifically subject to the Reliability Standard.
- p. 283 . . . modify the Reliability Standard to include an implementation plan for sub-100 kV facilities.
- p. 284 . . . remove the exceptions footnote from the "Effective Dates" section.

In Phase I of the project, the NERC Relay Loadability standard drafting team will either modify the PRC-023-1 Reliability Standard to incorporate the directed modifications or will propose equally efficient and effective alternative approaches that address the Commission's reliability-related concerns. *(In parallel with this effort, NERC plans to convene a panel of industry subject matter experts to develop a straw man proposal for the test Planning Coordinators must use to identify sub-200 kV facilities that are critical to the reliability of the Bulk Power System. The panel will collect industry feedback on the straw man test using the current standards development process that will be incorporated into Requirement R3 of PRC-023-1 by the Standard Drafting Team.)*

Phase II: Develop a new Standard Addressing Generator Relay Loadability
In Phase II of the project, a new Reliability Standard will be developed by the end of 2012 to address the subject of generator relay loadability in support of NERC's filing indicating it would develop such a standard and to address the following directive from Order No. 733:

- p. 108 . . . consider the PSEG Companies' suggestion in developing a Reliability Standard that addresses generator relay loadability.

As indicated in NERC's Order No. 733 clarification and rehearing request, NERC believes adding additional requirements to the PRC-023 standard in addition to developing a new Reliability Standard to address generator relay loadability could lead to confusion over applicability and the possibility of conflicting requirements. Therefore, NERC proposed in its clarification and rehearing request to address the issue of generator relay loadability in a new Reliability Standard, separate and distinct from the PRC-023 Reliability Standard, which is intended to address relays that protect transmission elements. Subject to the Commission's response to NERC's pending clarification and rehearing request, NERC plans to address generator relay loadability in a new Reliability Standard for applications where the relays are set with a shorter reach to protect the generator and the generator step-up transformer, and for applications where the relays are set with a longer reach to provide backup protection for transmission system faults. The standard drafting team will use relevant sections of the NERC technical reference document, Power Plant and Transmission System Protection Coordination Section 3.1 and Appendix E to develop the requirements by which generator relay loadability will be assessed.

<u>Phase III: Development of a New Standard Addressing the Issue of Protective Relay Operations Due To Power Swings</u>
In Phase III of the project, a new Reliability Standard will be developed to address the subject of protective relay operations due to power swings to address the following directive from Order No. 733 by the end of 2014:

- p. 150 - develop a Reliability Standard that requires the use of protective relay systems that can differentiate between faults and stable power swings and, when necessary, phases out protective relay systems that cannot meet this requirement.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Assurer	Monitors and evaluates the activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.
☒	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
PRC-023-1	Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability, and directed NERC, as the Electric Reliability Organization (“ERO”), to develop certain modifications to the PRC-023-1 standard through its Reliability Standards development process, to be completed by specific deadlines.
New Reliability Standard	Development of a New Standard Addressing Generator Relay Loadability
New Reliability Standard	Development of a New Standard Addressing the Issue of Protective Relay Operations Due To Power Swings

Related SARs

SAR ID	Explanation

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

Attachment 1 - Order No. 733 – Action Plan and Timetable

Note that the scope of the SAR is limited to addressing the directives highlighted in the table below.

Order No. 733 approved Reliability Standard PRC-023-1 – Transmission Relay Loadability, and directed NERC, as the Electric Reliability Organization ("ERO"), to develop certain modifications to the PRC-023-1 standard through its Reliability Standards development process, to be completed by specific deadlines and directed NERC to develop requirements to address issues related to Relay Loadability. The Order also directed development of two new Reliability Standards to address issues related to generator relay loadability and the operation of protective relays due to power swings. The following table lists the FERC directives in Order No. 733 and for each directive associates it with a project phase. Note that some of the tasks within each phase will be managed by NERC staff, not the standard drafting team.

Paragraph	Text	Project Phase/ Timeline
60	With respect to sub-100 kV facilities, we adopt the NOPR proposal and direct the ERO to modify PRC-023-1 to apply an "add in" approach to sub-100 kV facilities that are owned or operated by currently-Registered Entities or entities that become Registered Entities in the future, and are associated with a facility that is included on a critical facilities list defined by the Regional Entity. We also direct that additions to the Regional Entities' critical facility list be tested for their applicability to PRC-023-1 and made subject to the Reliability Standard as appropriate.	Phase I -- by March 18, 2011
69	Finally, pursuant to section 215(d)(5) of the FPA, we direct the ERO to modify Requirement R3 of the Reliability Standard to specify the test that planning coordinators must use to determine whether a sub-200 kV facility is critical to the reliability of the Bulk-Power System. We direct the ERO to file its test, and the results of applying the test to a representative sample of utilities from each of the three Interconnections, for Commission approval no later than one year from the date of this Final Rule.	Phase I -- Note NERC's pending request for rehearing filed on April 19, 2010 regarding this directive.
97	Finally, commenters argue that there should be some mechanism for entities to challenge criticality determinations. We agree that such a mechanism is appropriate and direct the ERO to develop an appeals process (or point to a process in its existing procedures) and submit it to the Commission no later than one year after the date of this Final Rule.	Phase I – by March 18, 2011
105	In light of the ERO's statement that within two years it expects to submit to the Commission a proposed Reliability Standard addressing generator relay loadability, we direct the ERO to submit to the Commission an updated and specific timeline explaining when it expects to develop and submit this proposed Standard.	Phase II – by the end of 2012
108	Finally, the PSEG Companies suggest that the ERO consider whether a generic rating percentage can be established for generator step-up transformers and, if so, determine that percentage. Although we do not adopt the NOPR proposal, we encourage the ERO to consider the PSEG Companies' suggestion in developing a Reliability Standard that addresses generator relay loadability.	Phase II – by the end of 2012
150	However, because both NERC and the Task Force have identified undesirable relay operation due to stable power swings as a reliability issue, we direct the ERO to develop a Reliability Standard that requires the use of protective relay systems that can differentiate between faults and stable power swings and,	Phase III – by the end of 2014

Paragraph	Text	Project Phase/ Timeline
	when necessary, phases out protective relay systems that cannot meet this requirement. We also direct the ERO to file a report no later than 120 days of this Final Rule addressing the issue of protective relay operation due to power swings. The report should include an action plan and timeline that explains how and when the ERO intends to address this issue through its Reliability Standards development process.	
162	We agree with the PSEG Companies and direct the ERO to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings.	Phase I – by March 18, 2011
186	However, we will adopt the NOPR proposal to direct the ERO to modify PRC-023-1 to require that transmission owners, generator owners, and distribution providers give their transmission operators a list of transmission facilities that implement sub-requirement R1.2.	Phase I – by March 18, 2011
203	We adopt the NOPR proposal and direct the ERO to modify sub-requirement R1.10 so that it requires entities to verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with the fault.	Phase I – by March 18, 2011
224	While we are not adopting the NOPR proposal, we direct the ERO to document, subject to audit by the Commission, and to make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant sub-requirement R1.12.	Phase I – by March 18, 2011
237	We adopt the NOPR proposal and direct the ERO to modify the Reliability Standard to add the Regional Entity to the list of entities that receive the critical facilities list. [sub-requirement R3.3]	Phase I – by March 18, 2011
244	We adopt the NOPR proposal and direct the ERO to include section 2 of Attachment A in the modified Reliability Standard as an additional Requirement with the appropriate violation risk factor and violation severity level.	Phase I – by March 18, 2011
264	After further consideration, and in light of the comments, we will not direct the ERO to remove any exclusion from section 3, except for the exclusion of supervising relay elements in section 3.1. Consequently, we direct the ERO to revise section 1 of Attachment A to include supervising relay elements on the list of relays and protection systems that are specifically subject to the Reliability Standard.	Phase I – by March 18, 2011
283	Additionally, in light of our directive to the ERO to expand the Reliability Standard's scope to include sub-100 kV facilities that Regional Entities have already identified as necessary to the reliability of the Bulk-Power System through inclusion in the Compliance Registry, we direct the ERO to modify the Reliability Standard to include an implementation plan for sub-100 kV facilities.	Phase I – by March 18, 2011

Attachment 1 - Order No. 733 – Action Plan and Timetable

Paragraph	Text	Project Phase/ Timeline
284	We also direct the ERO to remove the exceptions footnote from the "Effective Dates" section.	Phase I – by March 18, 2011
297	Finally, we direct the ERO to assign a "high" violation risk factor to Requirement R3.	Filed with the Commission on April 19, 2010
308	Consequently, we direct the ERO to assign a single violation severity level of "severe" for violations of Requirement R1.	Filed with the Commission on April 19, 2010
310	Accordingly, we direct the ERO to change the violation severity level assigned to Requirement R2 from "lower" to "severe" to be consistent with Guideline 2a.	Filed with the Commission on April 19, 2010
311	Finally, we direct the ERO to assign a "severe" violation severity level to Requirement R3.	Filed with the Commission on April 19, 2010

Standards Announcement

Ballot Pool Open November 1 – December 2, 2010
Comment Period Open November 1 – December 16, 2010

Now available at: http://www.nerc.com/filez/standards/SAR_Project%202010-13_Order%20733%20Relay%20Modifiations.html

Project 2010-13: Revisions to Relay Loadability for Order 733

PRC-023-2 – Transmission Relay Loadability has been posted for a 45-day formal comment period, and a ballot pool is being formed during the first 30 days of the 45-day comment period.

Ballot Pool Open through 8 a.m. on December 2, 2010

A ballot pool is being formed during the first 30 days of the 45-day formal comment period, and an initial ballot will be conducted during the last 10 days of this comment period.

Registered Ballot Body members may join the ballot pool to be eligible to vote in the upcoming ballot at the following page: https://standards.nerc.net/BallotPool.aspx

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2010-13_Rev RLO 733_in

Formal 45-day Comment Period Open through 8 p.m. on December 16, 2010

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page:
http://www.nerc.com/filez/standards/SAR_Project%202010-13_Order%20733%20Relay%20Modifiations.html

Next Steps

An initial ballot will be conducted during the last 10 days of the 45-day formal comment period. The drafting team will consider all comments (those submitted with a comment form, and those submitted with a ballot) and will determine whether to make additional changes to the standard. The team will post its response to comments and, if the standard has only minor changes, will post the standard and conduct a 10-day recirculation ballot.

Project Background

When FERC issued Order 733, approving PRC-023-1 — Transmission Relay Loadability, it directed several changes to that standard and also directed development of one or more new standards within specified time periods. NERC filed for clarification and rehearing asking for clarity and an extension of time to address the directives; however, without a response to the requests for clarification and rehearing, NERC must progress as though these requests will be denied.

The SAR for Project 2010-13 subdivides the standard-development-related directives into three phases. Phase I

addresses the specific directives from Order 733 that identified required modifications to various elements within PRC-023-1. Phase II addresses directives associated with development of a new standard to address generator relay loadabilty. Phase III addresses directives associated with writing requirements to address protective relay operations due to power swings.

Applicability of Proposed PRC-023-2

Distribution Providers that own specific facilities (see standard for details)
Generator Owners that own specific facilities (see standard for details)
Planning Coordinators
Transmission Owners that own specific facilities (see standard for details)

Standards 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 Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

Individual or group. (38 Responses)
Name (25 Responses)
Organization (25 Responses)
Group Name (13 Responses)
Lead Contact (13 Responses)
Question 1 (35 Responses)
Question 1 Comments (38 Responses)
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Individual
Joe Petaski
Manitoba Hydro
Yes
Yes
Yes
Yes
No
1. We don't think that the system would change that fast to warrant the additional work of conducting an assessment every year. The entities involved have 24 months to make the necessary changes as given in R7. If an annual assessment is required then this should be added as a requirement to TPL-001-2 rather than buried in PRC-023. It would be more efficient to perform an assessment over the 10-year planning horizon every 2-3 years. Critical facilities identified in the assessment can be monitored in the in-between years to ensure construction schedules are on track and the need is still there. One initial detailed assessment of the current year facilities could be done but then the assessment should be more focused on additions and changes. 2. The VSLs for R6 are too severe. The system doesn't change that rapidly and getting the list to the entities involved before 60 days does not impact reliability given that they have 2 years to comply with changes.
No
The effective date should not be a uniform date, it should be dependent on the number of circuits that have been identified and determined as critical circuits for an individual utility.
No
Effectively, there is no substantial difference between the protection elements described in section 1.6 and the protection elements described on second bullet in Section 2.1. Why should the protection elements in section 1.6 be included? During loss of communication, the supervisory elements associated with current based, communication-assisted schemes (such as line current differential scheme and phase comparison scheme) may be the only protection elements to provide high speed protection which may be necessary from system reliability perspective. As a result, these supervisory elements should be set low enough to ensure that they can detect all fault condition. Since these supervisory elements are only in effect under loss of communication contingency, I don't think they should be subjected to the same requirements as those load responsive elements under normal condition. They should be treated the same as those elements described on the first bullet in section 2.1.
No
In attachment B and the standard, there's discussion of 15 min., up to 4 hour, 4-8 hour and more than 8 hour ratings. This is very prescriptive and doesn't match the requirements in the Facility rating methodology standard or the model building limitations. It seems there is a disconnect between the FAC, TPL and PRC standards.
Group
Electric Market Policy

Mike Garton
Yes
Yes
Yes
Yes
Yes
Yes
Yes
5.1 Requirement R1. Dominion would like to see the exception of "switch on to fault" schemes added back in.
Individual
Mace Hunter
Lakeland Electric
Yes
Yes
Yes
Yes
No
In R6.2 the phrase “for the purposes of the Compliance Registry and” is used. The same phrase is also used under Applicability in sections 4.2.3 and 4.2.6. What is the purpose of this phrase in these sections? I do not think that the phrase has any value in these locations. The phrase is also used in the PRC-023 – Attachment B in the second bullet under “Criteria”. It seems to imply that if a circuit is identified as a critical facility that fact could be used to drive registration of an entity that otherwise may not require registration. If that is the intent then I would suggest modifying the phrase in the attachment to “that may require entity registration in the Compliance Registry “
Yes
Yes
Yes
Group
Potomac Holdings Inc & Affiliates
David K Thorne
Yes
Please note that a typographical error exists in Requirement R1 Criterion 9. The sentence should end with the phrase “flow from the load to the system under any system configuration”. The words load and system have been inadvertently omitted in both this draft and the previous draft.
Yes
Yes
In the SDT’s response “Consideration of Comments on Revisions to Relay Loadability for Order 733 SAR and an initial set of proposed requirements – Project 2010-13” dated November 1, 2010, the SDT proposed to establish the effective date for requirements R4 & R5 as “the first day of the first calendar quarter following 24 months after regulatory approvals.” However in the latest draft of the standard the 24 month requirement was replaced with 6 months. Which is correct?
Yes
In the SDT’s response “Consideration of Comments on Revisions to Relay Loadability for Order 733 SAR and an initial set of proposed requirements – Project 2010-13” dated November 1, 2010, the SDT proposed to establish the effective date for requirements R4 & R5 as “the first day of the first calendar quarter following 24 months after regulatory approvals.” However in the latest draft of the standard the 24 month requirement was replaced with 6 months. Which is correct?
Yes

Yes
No
The current wording of section 1.6 is a significant improvement over the previous version. The intent of this section was to specifically address phase overcurrent supervising elements (i.e. phase fault detectors) associated with pilot wire, phase comparison, and line current differential schemes where the scheme is capable of tripping for loss of communications. However, we believe that the term “current-based communication-assisted schemes” is too generic and may be confusing without mention of the specific schemes to which this requirement applies. Also, only phase overcurrent supervising elements are in scope, not ground overcurrent supervising elements. Therefore, to clarify the requirement we suggest replacing the current wording with either “Phase overcurrent supervisory elements (i.e. phase fault detectors) associated with pilot wire, phase comparison, and line current differential schemes, where the scheme is capable of tripping for loss of communications” or “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”.
Yes
Individual
Joe O'Brien for Tom Nappi
NIPSCO
No
The mechanical withstand is not an appropriate value because every fault event will reduce the life of a transformer. Setting the limit at the maximum expected one time event limit will prematurely destroy the transformers. Maybe a sliding scale would be better with each transfromer owner to decided how much expected life to risk for faults.
No
We believe this is already included
No
We're not sure what the value is in this requirement?
No
We believe the R1 criterion 12 is needed- but the reporting requirment is not.
No
Only the owner or TO GO DP should apply the criteria – which can be then reported to the PC
No
We believe only the owners of facilities should have this requirment, not the PC
No
Don’t know what is referred to here except maybe a current differential scheme. There is no need for this added requirement.
Yes
The method seems OK but the standard requirement R1 should be changed because lower voltage lines have far more resistance and arc resistance needs to be included. General Comments: We think that the proposed revised standard incorrectly assigns responsibility to the PC instead of the TO,GO DP Also, the new standard forces compliance on lower voltage lines which would limit protection of equipment which will ultimately lead to many fewer networked lines and a less reliable electric system.
Individual
Nicholas Klemm
Western Area Power Administration
No
Established industry standards and practices have defined the mechanical damage portion of the transformer curve to apply for repetitive faults. Neither FERC nor NERC should have the right to contradict established technical practices. Entities should be able to coordination protection systems taking into account protection and controls (e.g. the use of lockouts) which prevent repetitive exposure to mechanical damage thereby alleviating cumulative effects. Also, it is not clear what "transmission line relays on transmission lines terminated only with a transformer..." applies to. Need clarification.
Yes
Yes
Yes
No
Feel that NERC is delving too much into the technical details. Should allow Planning Coordinators to establish their own study methodologies.
Yes

No
Both the FERC order and section 1.6 are unclear.
No
Is this necessary? Allow Planning Coordinators to do their jobs and decide which circuits are important.
Individual
Richard Burt
Minnkota Power Cooperative, Inc.
Yes
Yes
Yes
Yes
No
Many facilities with voltages between 100kV and 200kV will only impact a well-defined local load region if they trip. There is no risk of cascading outages beyond the local load region. The criteria in Attachment B should allow these types of facilites to be dismissed from evaluation.
Yes
Yes
No
Many facilities with voltages between 100 kV and 200 kV will only impact a well-defined local load region if they trip. There is no risk of cascading outages beyond the local load region. The criteria in Attachment B should allow these facilities to be dismissed from further evaluation.
Group
Northeast Power Coordinating Council
Guy Zito
No
Clarification is needed on whether criterion 10 requires a transformer to have load responsive protection to protect from mechanical damage, either from internal faults, or through faults. If load responsive protection for the transformer element does not presently exist, i.e. only differential protection exists for the transformer element, will load responsive transformer protection have to be added to comply with this criterion? The wording in criterion 10 should be changed to “Set transformer fault protection relays or transmission line relays on transmission lines terminated only with a transformer to …….” Is this criteria requiring that a transformer with only differential protection and no other load responsive remote protection be supplemented additional load responsive protection? The loading on phase angle regulators, and series reactors should be considered and mentioned. Also, there appears to be words missing in criterion 9 of R1: “the maximum current flow from the ? to the ? under any system configuration.” From the NERC Webinar on 11/23/10 the intention was to address the possible locations where phase protection for the transformer could exist and not imply that this protection was needed at both locations.
Yes
Yes
Yes
Yes
Yes
Yes
No
B2. Item B2 adds significant confusion to the process. The long term planning horizon may include transmission projects which have not even been built or alternative system configurations which do not exist, making it impossible for affected parties to set their relays appropriately. Suggested replacement language to avoid this issue: “Each circuit that is a monitored element of an IROL, assuming that all transmission elements are in service and the system is under normal conditions.” B3. This item indicates that the circuits to be considered are to be agreed to by the plant owner and the Transmission Entity. Attachment B is applicable to the Planning Coordinator. If this item is by agreement by the plant and the Transmission Entity it should be removed from Attachment B and placed elsewhere in the document. If this is intended to apply to the Planning Coordinator, Transmission Entity should be replaced with Planning Coordinator. Why does B3

only apply to Nuclear Power Plants? B4. This criterion is overly stringent and should be deleted. The system is neither planned nor operated to allow for two overlapping outages without operator action in between. If this criterion is retained, it should be made consistent with the requirements of TPL-003 where operator actions can be assumed between the first and second contingencies. Since a similar comment was made previously, more information is being provided following. 1. Since the system is neither planned nor operated to two overlapping outages in between, such testing may result in unsolved cases, or voltages well below criteria. In the case of an unsolved case, there are no flows to evaluate, making this standard impossible to apply. In the case of a solved case with voltages well below criteria, currents are likely to be incredibly high and therefore viewed as unrealistic. These concerns may limit the contingency selection to those which are not severe, eliminating any perceived benefit from this testing. 2. There is no guidance provided on how the system should be dispatched in the model upon which the overlapping contingencies are tested. This will result in significant discrepancies between the base assumptions used by the various Planning Coordinators. The contents of this standard should be reviewed to reflect the new definition of the Bulk Electric System.
Individual
Kathleen Goodman
ISO New England Inc.
No
B2. Item B2 adds significant confusion to the process. The long term planning horizon may include transmission projects which have not even been built or alternative system configurations which do not exist, making it impossible for affected parties to set their relays appropriately. Suggested replacement language to avoid this issue: “Each circuit that is a monitored element of an IROL, assuming that all transmission elements are in service and the system is under normal conditions.” B3. This item indicates that the circuits to be considered are to be agreed to by the plant owner and the Transmission Entity. Attachment B is applicable to the Planning Coordinator. If this item is by agreement by the plant and the Transmission Entity it should be removed from Attachment B and placed elsewhere in the document. If this is intended to apply to the Planning Coordinator, Transmission Entity should be replaced with Planning Coordinator. B4. This criterion is overly stringent and should be deleted. The system is neither planned nor operated to allow for two overlapping outages without operator action in between. If this criterion is retained, it should be made consistent with the requirements of TPL-003 where operator actions can be assumed between the first and second contingencies. Since a similar comment was made previously, more information is being provided in this set of comments. 1. Since the system is neither planned nor operated to two overlapping outages in between, such testing may result in unsolved cases, or voltages well below criteria. In the case of an unsolved case, there are no flows to evaluate, making this standard impossible to apply. In the case of a solved case with voltages well below criteria, currents are likely to be incredibly high and therefore viewed as unrealistic. These concerns may limit the contingency selection to those which are not severe, eliminating any perceived benefit from this testing. 2. There is no guidance provided on how the system should be dispatched in the model upon which the overlapping contingencies are tested. This will result in significant discrepancies between the base assumptions used by the various Planning Coordinators.
Group
Pacific Northwest Small Public Power Utility Comment Group
Steve Alexanderson
No
The comment group finds R1.10 very confusing when attempting to understand it in the context of IEEE C57.109-1993. C57.109 identifies a solid curve as the thermal damage curve, while a dotted dog leg is the mechanical damage curve. Generally the dog leg is only considered for those class II and III transformers subjected to frequent through faults and all class IV transformers. Is the intent of the SDT to require this level of protection for all transformers regardless of through fault frequency and/or transformer class? If the SDT really meant to protect transformers from thermal or combination damage, please note that it is not possible to completely protect transformers from the thermal damage of low current long duration faults while still complying with the 150% of maximum rating. The thermal damage curve extends down to twice the base current. A footnote in C57.109 states that base current is established from the lowest nameplate kVA rating. A typical transformer with two stages of cooling will have a high nameplate rating of 1.67 times this base rating. The first bullet of R1.10 states affected entities must allow 1.5 times the maximum, so we are up to 2.5 times the base rating. Since we must allow this much without tripping, the relay must be set even higher. 1.2 times would be a secure margin, so the relay is set to pickup at 3 times the base rating. This setting would of course violate the first part of R1 criterion 10 because the transformer’s fault capability would be exceeded for faults between 2 and 3 times the base rating. We also note that criterion 11 is apparently an exception to criterion 10, but this is not altogether clear since 10 is for fault protection while 11 is for overload protection. Please rewrite this (these) criterion (criteria) to clarify the SDT’s intent(s).
Yes
Yes
No
The FERC Order 773 page 224 states that this information is to be made available to the entities “by request.” Unless a request happens to coincide with the annual submittal, this order is not being addressed. There is also no requirement that

the Regional Entity make the lists available to the other entities as ordered. We don’t believe the intent of the order was achieved in R5.
Yes
Yes
Yes
No
We thank the SDT for addressing our concern regarding radially operated circuits. We note, however, that the key word “operated” from the consideration of comments was dropped before it reached the standard. Please change the last bullet of B4 to: "Radially operated circuits serving only load are excluded."
Individual
Greg Rowland
Duke Energy
Yes
Yes
Yes
Yes
No
• R6.1 and R6.2 unnecessarily duplicate the first part of Attachment B, and should be deleted from R6. • R6.3 and R6.4 are both associated with maintaining the list and should be combined into a separate requirement (new R7), with its own VRF and VSLs. Including the year for a facility should apply to all the criteria, not just B4. Suggested wording for new R7: “Maintain a list of circuits that must comply with this standard due to meeting Attachment B criteria. For each circuit, include the applicable criteria and the year studied for which the criteria first applies, when a facility is added to the list.” • R6.5 should become a new R8 with its own VRF and VSLs. No wording changes needed.
No
Since the Attachment B criteria are applied beyond the operating horizon, R7 should be rewritten (and also renumbered as R9). Suggested wording: “ Each Transmission Owner, Generator Owner, and Distribution Provider shall implement Requirement R1, Requirement R2, Requirement R3, Requirement R4, and Requirement R5 for each facility that is added to the Planning Coordinator’s list of facilities that must comply with this standard pursuant to Requirement R6, by the first day of the first calendar quarter of the year in which Attachment B criteria first apply. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]
Yes
No
• B2 needs additional clarification, because identification could be in the short term or long term planning horizon. Suggested rewording: “B2. Each circuit that is a monitored Element of an IROL where the IROL was determined beyond the operating horizon.” • B3 needs additional clarification, to explicitly identify the necessary agreement between the plant owner and Transmission Entity. Suggested rewording: “Each circuit that forms a path (as agreed to by the plant owner and the Transmission Entity pursuant to NUC-001) to supply off-site power to nuclear plants.
Individual
Tim Hinken
Kansas City Power & Light
Yes
Yes
No
We do not believe this requirement is needed. Limiting a relay setting to 115% of the associated transmission line’s highest seasonal 15 minute rating does not equate to a line that will trip before the operator has time to intervene. It does not mean the line will trip in 15 minutes. In fact, the operator should be taking action well in advance of reaching a 15 minute limit and the operator is likely only using the 15 minute rating in extreme circumstances. Furthermore, PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings including those limited by relays. As a result, neither PRC-023-2 R3 nor R4 is even needed. We assume the drafting team must be aware of these FAC standard requirements because they did not even require reporting to the Reliability

Coordinator, Planning Coordinator and Transmission Operator of those circuits that are actually limited by the relay per criterion 12. We agree that FAC-008-1 and FAC-009-1 collectively establish the necessary requirements to compel the Transmission Owner and Generator Owner to communicate these relay limited circuits and that no additional requirements are necessary.
No
While we don't necessarily have an issue with the equipment owner communicating these relay limited circuits to the Regional Entities, we don't believe this is needed for reliability and therefore it should not be included in the reliability standard. Given that it is unclear what the information will even be used for, if it will be needed long-term, and that it is likely will not change much, if at all, from year to year, we believe a data request through NERC's Rules of Procedure section 1600 would be more appropriate. In that way, we don't have to modify the standard later when NERC and the Regions determine they don't need the data annually.
No
It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV that are part of the Bulk Electric System. This information is not readily available and there is no requirement for the Regional Entity to communicate it to them. Thus, inaction by the auditor (i.e. Regional Entity) could actually cause the Planning Coordinator to violate this requirement. This is clearly a conflict of interest. Why does the Planning Coordinator need to identify which circuits are identified per criteria B4? There is no justification given for this need and there is nothing else that appears to require action as a result of this information. Thus, it is purely administrative and should be removed. Registered entities should never be subject to potential sanctions for violations of purely administrative portions of requirements. Why does the Planning Coordinator need to provide this information to the Reliability Coordinator? There is nothing for the Reliability Coordinator to do with the information. The Reliability Coordinator only needs to be informed if equipment becomes derated and then that should occur through the normal communication of ratings per FAC-009-1.
No
We do not believe that R7 is needed. The applicability section of the standard is clear that the standard applies to those circuits identified in R6. This requirement could be construed as potential for double jeopardy because failure to comply with Requirements 1-5 for represent a violation of both Requirement 7 and Requirement 1-5.
Yes
No
While we appreciate the drafting team's effort to refine the flowgate criteria from the last posting, the modifications do not go far enough and still do not reflect the use of flowgates. NERC's definition of flowgate includes two components. Let's focus on the first component which represents those flowgates defined in the IDC. Because IDC flowgates list is updated monthly and the IDC users can add temporary flowgates to the IDC at any time, this is an inappropriate list to use. We appreciate the drafting team's attempt to resolve this issue by including the caveat "that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator." However, this really only confuses the matter and does not solve it. Reliability Coordinators add flowgates to manage real-time congestion. Planning Coordinators do not. Per the NERC functional model, they do not even have a role in deciding which flowgates to add to the IDC. Flowgates are added to the IDC to mitigate existing, known congestion points not congestion points identified in a long-term planning study that may never materialize due to changing conditions. Thus, IDC flowgates should be specifically excluded. Now let us focus on the second component of flowgate. The second component is much like the first component in that is it a mathematical construct to analyze the impact of power flows on the BES except is not required to be included in the IDC. There is nothing in the definition of a flowgate to give credence that is represents anything more that point to calculate power flows and the impact of transactions. Flowgates are primarily used to manage congestion on the system and to sell transmission system. Because it is convenient to select a group of lines as a proxy to sell transmission service or manage congestion does not mean that those group of lines represent a reliability issue. Thus, we do not believe any flowgates should be included in the list. Any true reliability issues can be identified through the TPL studies and those facilities that do not meet the performance requirements are what should be used. We do not support criterion B4. It exceeds what is required in the TPL standards and what is required per the reliability directive in Order 729. The TPL standards allow system operator intervention for category C3 contingencies between the two independent Category B contingencies. This standard should not exceed those requirements in the TPL standards. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test "must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning." Paragraph 80 states that "the test must be consistent with the general reliability principles embedded in the existing series of TPL" standards. Thus, exceeding the TPL standards could be argued as deviating from the directive. The directive is to be consistent not exceed. Exceeding the TPL standards is not consistency. In response to comments that did not support this criterion during the first posting, the standards drafting team responded with "Testing multiple element contingencies while accounting for system adjustments between each element outage will not yield any facilities to be subject to PRC-023 as long as TPL-003 system performance requirements are met." We think the drafting team missed a basic point about the standard. The issue is not whether the registered entity develops and documents corrective actions actions plans TPL-003-0a R2 and R3. The issue is if the system as currently designed meets the performance requirements in TPL-003-0a R1 which allows for operator interventions on Category C3 contingencies. For those C3 contingencies that don't currently meet the performance obligations after operator interventions, the subject facilities would be included PRC-023-2 R6 list of facilities.
Individual
Andrew Pusztai
American Transmission Company
Yes

Yes
Yes
Yes
Yes
Except ATC is recommending the following wording change for Requirement R 6.2 which provides clarification on the application of the criteria: “Apply the criteria to the following Elements in its Planning Coordinator Area, if any: those transmission lines operated below 100 kV and those transformers with low voltage terminal connections below 100 kV that the Regional Entity has identified as critical facilities for the purposes of the Compliance Registry.”
No
ATC believes it is difficult to determine without knowing the full scope of work. Until the Planning criteria can be determined, the scope is unknown. Assuming not many assets are added, two years would be a more reasonable amount of time.
Yes
Yes
Group
Tennessee Valley Authority
Joshua Wooten
Yes
Yes
Yes
Yes
No
Per Requirement R6 criterion 2, the Planning Coordinator is better suited to analyze the subsystem and its effect on the BES than the Regional Entity, so “Regional Entity” should be replaced with “Planning Coordinator”. Please also see Question 8 comment concerning the use of “flowgate” in Attachment B section B1.
Yes
Yes
No
The NERC Glossary defines a flowgate as: 1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System. The IDC flowgates change often thus making it difficult to coordinate those changes with the critical lines list provided by the Planning Coordinator in Attachment B section B1. We assume that No. 2 above is the definition that the SDT was referring. However, for clarity, we recommend that either the word “flowgate” be specifically defined in Attachment B or removed.
Individual
David Burke
Orange and Rockland Utilities, Inc.
No
Clarification is needed on whether criterion 10 requires a transformer to have load responsive protection to protect from mechanical damage. The wording in criterion 10 should be changed to “set transformer fault protection relay or transmission line relay on transmission line terminated with only a transformer.” Is this criteria requiring that a transformer with only differential protection and no other load responsive remote protection be mitigated with additional load responsive protection? The loading on phase angle regulators, and series reactors should also be considered and mentioned.
No
What is the expectation for verifying that the out-of-step blocking elements allow tripping of phase protection relays for faults that occur during the loading conditions used to verify transmission line relay loadability? It would be costly and time consuming to verify this. To comply with this requirement, utilities may have to remove OOS protections all together. This should be able to be tested during routine trip testing. Between the trip testing procedures, and relay calibrations this requirement should be satisfied, and easily documented.
Yes

Yes
Yes
Yes
Yes
No
Why does B3 only apply to Nuclear Power Plants only?
Group
Tri-State G & T System Protection
Bill Middaugh
No
There can be cases where the transformer withstand capability will be exceeded if 150% of the applicable maximum transformer rating is used for the pickup of overcurrent relays. The requirement cannot then be met if no transformer emergency rating is established. Modify to indicate that if the loading requirement violates the protection requirement, then the protection requirement should be used while allowing the maximum loading possible without violating the protection requirement.
Yes
No
We believe that the list of facilities with transmission line relays that use Requirement R1 criterion 2 needs to be given only to the Transmission Operators as directed by Paragraph 186 of FERC Order no. 733, and not also to the Planning Coordinators and Reliability Coordinators. We also believe that an initial submittal is sufficient until any responsible entity begins or stops using that criterion on any element. Periodic duplicate submittals are unnecessary and unique submittals would more easily identify the loadability issues that the operators need to consider. The FERC Order did not require annual submittals.
No
Paragraph 224 of FERC Order no. 733 requires that the ERO document and have available upon request the list of facilities that use this criterion. The proposed standard is not applicable to the Regional Entity so there is no method to require the RE to provide the data to the ERO. That seems to indicate that the data should be provided to the ERO rather than the Regional Entity. We also believe that an initial submittal is sufficient until any responsible entity begins or stops using that criterion on any element. Periodic duplicate submittals are unnecessary and unique submittals would more easily identify the loadability issues that the operators need to consider. The FERC Order did not require annual submittals.
Yes
Yes
Yes
Yes
While we agree that it is a technically sound approach, we have concerns that the criterion B4 is over-burdensome. Paragraph 82 of FERC Order 733 indicates that the existing TPL simulations and assessments should be a component of the test. By excluding manual intervention in the assessments the Attachment is expanding the scope beyond the Commission's Order. We think there should be a test based on the existing assessments required by the TPL standards that would then trigger a subsequent test with no manual intervention. An example would be if an element's loading exceeded 100% of its Facility Rating using the normal assessment, then the assessment with no manual intervention would be applied and subsequent steps of criterion B4 would be followed. We think that criterion B5 is too vague, may be discriminatory, is unnecessary, and should be removed. There is very little basis listed for this criterion above and beyond those listed in criterion B4, the criterion may be applied discriminatorily or differently even within the same interconnection, it potentially excludes the protection system owner from having input in the process, and there is no redress for appeal by the owner. It seems highly unlikely that elements that are not identified through criterion B4 will need to be included. If some form of criterion B5 is included in Attachment B, then it needs to better define a technical basis for the request for inclusion, a procedure to initiate the request for inclusion, due process defined for evaluation of the request, and inclusion of the protection system owner in the evaluation process and the agreement.
Individual
J. S. Stonecipher, PE
City of Jacksonville Beach, FL dba/Beaches Energy Services
Yes
However, R1 and R2 have binary VSLs, where they should be percentages of all relays that need to meet the standard based on statistical sampling.
Yes

R1 and R2 have binary VSLs, where they should be percentages of all relays that need to meet the standard based on statistical sampling. (See previous comment for R1.)
No
No, that is way too frequent. It should be a much longer time criteria, say 5 years, with a requirement that if there is a CHANGE, the information is sent to the PC, TO and RC.
No
No, once again, that is way too frequent and creates another unnecessary burden for record keeping. It should be a much longer time criteria, say 5 years, with a requirement that if there is a CHANGE, the information is sent to the PC, TO and RC.
Yes
Yes
Yes
Yes
Attachment B, the criterion in B4 seem rather arbitrary; but, the numbers seem reasonable.
Group
Midwest ISO Standards Collaborators
Jason Marshall
Yes
No
We do not believe this requirement is needed. Limiting a relay setting to 115% of the associated transmission line's highest seasonal 15 minute rating does not equate to a line that will trip before the operator has time to intervene. It does not mean the line will trip in 15 minutes. In fact, the operator should be taking action well in advance of reaching a 15 minute limit and the operator is likely only using the 15 minute rating in extreme circumstances. Furthermore, PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings including those limited by relays. As a result, neither PRC-023-2 R3 nor R4 is even needed. We assume the drafting team must be aware of these FAC standard requirements because they did not even require reporting to the Reliability Coordinator, Planning Coordinator and Transmission Operator of those circuits that are actually limited by the relay per criterion 12. We agree that FAC-008-1 and FAC-009-1 collectively establish the necessary requirements to compel the Transmission Owner and Generator Owner to communicate these relay limited circuits and that no additional requirements are necessary.
No
While we don't necessarily have an issue with the equipment owner communicating these relay limited circuits to the Regional Entities, we don't believe this is needed for reliability and therefore it should not be included in the reliability standard. Given that it is unclear what the information will even be used for, if it will be needed long-term, and that it is likely will not change much, if at all, from year to year, we believe a data request through NERC's Rules of Procedure section 1600 would be more appropriate. In that way, we don't have to modify the standard later when NERC and the Regions determine they don't need the data annually.
No
It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV that are part of the Bulk Electric System. This information is not readily available and there is no requirement for the Regional Entity to communicate it to them. Thus, inaction by the auditor (i.e. Regional Entity) could actually cause the Planning Coordinator to violate this requirement. This is clearly a conflict of interest. Why does the Planning Coordinator need to identify which circuits are identified per criteria B4? There is no justification given for this need and there is nothing else that appears to require action as a result of this information. Thus, it is purely administrative and should be removed. Registered entities should never be subject to potential sanctions for violations of purely administrative portions of requirements. Why does the Planning Coordinator need to provide this information to the Reliability Coordinator? There is nothing for the Reliability Coordinator to do with the information. The Reliability Coordinator only needs to be informed if equipment becomes derated and then that should occur through the normal communication of ratings per FAC-009-1.
No
We do not believe that R7 is needed. The applicability section of the standard is clear that the standard applies to those circuits identified in R6. This requirement could be construed as potential for double jeopardy because failure to comply with Requirements 1-5 would represent a violation of Requirement 7 also.
Yes
No
While we appreciate the drafting team's effort to refine the flowgate criteria from the last posting, the modifications do not

go far enough and still do not reflect the use of flowgates. NERC's definition of flowgate includes two components. Let's focus on the first component which represents those flowgates defined in the IDC. Because IDC flowgates list is updated monthly and the IDC users can add temporary flowgates to the IDC at any time, this is an inappropriate list to use. We appreciate the drafting team's attempt to resolve this issue by including the caveat "that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator." However, this really only confuses the matter and does not solve it. Reliability Coordinators add flowgates to manage real-time congestion. Planning Coordinators do not. Per the NERC functional model, they do not even have a role in deciding which flowgates to add to the IDC. Flowgates are added to the IDC to mitigate existing, known congestion points not congestion points identified in a long-term planning study that may never materialize due to changing conditions. Thus, IDC flowgates should be specifically excluded. Now let us focus on the second component of flowgate. The second component is much like the first component in that is it a mathematical construct to analyze the impact of power flows on the BES except is not required to be included in the IDC. There is nothing in the definition of a flowgate to give credence that is represents anything more than point to calculate power flows and the impact of transactions. Flowgates are primarily used to manage congestion on the system and to sell transmission system. Because it is convenient to select a group of lines as a proxy to sell transmission service or manage congestion does not mean that those group of lines represent a reliability issue. Thus, we do not believe any flowgates should be included in the list. Any true reliability issues can be identified through the TPL studies and those facilities that do not meet the performance requirements are what should be used. We do not support criterion B4. It exceeds what is required in the TPL standards and what is required per the reliability directive in Order 729. The TPL standards allow system operator intervention for category C3 contingencies between the two independent Category B contingencies. This standard should not exceed those requirements in the TPL standards. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test "must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning." Paragraph 80 states that "the test must be consistent with the general reliability principles embedded in the existing series of TPL" standards. Thus, exceeding the TPL standards could be argued as deviating from the directive. In response to comments that did not support this criterion during the first posting, the standards drafting team responded with "Testing multiple element contingencies while accounting for system adjustments between each element outage will not yield any facilities to be subject to PRC-023 as long as TPL-003 system performance requirements are met." We think the drafting team missed a basic point about the standard. The issue is not whether the registered entity develops and documents corrective action plans TPL-003-0a R2 and R3. The issue is if the system as currently designed meets the performance requirements in TPL-003-0a R1 which allows for operator interventions on Category C3 contingencies. For those C3 contingencies that don't currently meet the performance obligations after operator interventions, the subject facilities would be included PRC-023-2 R6 list of facilities.
Individual
Thad K. Ness
American Electric Power
No
American Electric Power sees two issues with R1's Criterion 10. First, transformer "mechanical withstand capability" is undefined, vague, and subject to various interpretations. The terminology used in this criterion must be more tightly defined to prevent ambiguity or else referenced to some agreed-upon standard such as IEEE C57.109-1993. Second, American Electric Power agrees that it is appropriate for the 150% and 115% settings criteria to apply to line relays terminated only with a transformer. However, Criterion 10 seems to assume that transmission line relays on transmission lines terminated with a transformer are also typically intended to protect the transformer. This is not normally or necessarily true. If the line relays are not intended to protect the transformer and as long as the transformer relaying properly protects the transformer from mechanical damage, there is no reason for Criterion 10 to apply to the line relays. To address these two deficiencies in Criterion 10, American Electric Power sets forth the following two-part replacement language for Criterion 10: 10.1 Set transformer fault protection relays such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability as defined by IEEE C57.109-1993 or its successor standard and 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. 10.2 Set 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. If the transformer fault protection relays on the line-terminated transformer do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability, then the transmission line relays do not also need to provide the same protection against transformer mechanical damage.
Yes
Yes
Yes
No
The wording under Sections 4.2.3, 4.2.6, 6.2, and the applicability portion of Attachment B needs to be made consistent to avoid any misinterpretations and confusion. - Section 4.2.3 – Delete the portion that reads "... and the Planning Coordinator has determined are required to comply with this standard" for this section to read the same as the associated sentence under the applicability portion of Attachment B. - Section 4.2.6 – Same comment as Section 4.2.3 (above). - Section 6.2 – Reword to read: "Apply the criteria to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that the Regional Entity has identified as critical for the purposes of the

Compliance Registry."
No
Need to provide a 60-month timeline to implement the noted requirements for each facility that is added to the Planning Coordinator's initial list of facilities that must comply with this standard, versus the 24-month timeline to implement the noted requirements for each facility that is added to the Planning Coordinator's established list of facilities that must comply with this standard. This is a practical consideration that recognizes the high likelihood that the number of facilities that will be identified during development of the initial list of facilities will be many times greater than the incremental number of facilities that will be identified during the annual assessments and added to the established list of facilities. In addition, need to specify under this requirement whether any facilities that drop off the Planning Coordinator's list of facilities while still within the applicable (60-month or 24-month) implementation timeline must still comply with this standard.
No
The wording of Attachment A, section 1.6 needs to be made consistent to avoid any confusion. 1.6 Reword to read: "Supervisory elements used as fault detectors associated with pilot wire or current differential protection systems where the system is capable of tripping for loss of communications".
No
Include the following refinements to the criteria for determining the facilities that must comply with the standard: o Add new B5 that reads: "Each circuit that is operated below 100 kV that the Regional Entity has identified as critical for the purposes of the Compliance Registry." o Renumber B5 to B6. o Need to consider the amount of load that is placed at risk when determining whether the circuit must comply with the standard. The threshold should be set at the DOE reporting level of 300 MW. o Need to include a review and appeals process as part of the annual assessment for the Planning Coordinator to review the proposed facilities with the transmission entity prior to adding those facilities to the Planning Coordinator's list of facilities that must comply with the standard.
Individual
Steve Wadas
Nebraska Public Power District
Yes
Yes
No
NERC does not need a separate requirement for TOs, GOs, and DPs to specifically report R1, criterion 2. If they meet the requirement the line will not trip. If they meet the requirement and the line is overloaded the operator will receive an alarm and will take action within 15 minutes.
Yes
Yes
If attachment B is kept then the PC should determine which transmission elements must comply with the standard.
Yes
Yes
No
Attachment B, Criteria B1 could add at least 24 transmission elements which are transmission lines operated at 100kv to 200kv. After reviewing the MRO and SPP criteria these lines will not be included per PRC-023. Loss of any of these lines will not cause a cascading outage which PRC-023 is intended to prevent.
Group
MRO's NERC Standards Review Subcommittee
Carol Gerou
Yes
Yes
No
We do not believe this requirement is needed. Limiting a relay setting to 115% of the associated transmission line's highest seasonal 15 minute rating does not equate to a line that will trip before the operator has time to intervene. It does not mean the line will trip in 15 minutes. In fact, the operator should be taking action well in advance of reaching a 15 minute limit and the operator is likely only using the 15 minute rating in extreme circumstances. Furthermore, PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings including those limited by relays. As a result, neither PRC-023-2 R3 nor R4 is even needed. We assume the drafting team must be aware of these FAC standard requirements because they did not even require reporting to the Reliability

Coordinator, Planning Coordinator and Transmission Operator of those circuits that are actually limited by the relay per criterion 12. We agree that FAC-008-1 and FAC-009-1 collectively establish the necessary requirements to compel the Transmission Owner and Generator Owner to communicate these relay limited circuits and that no additional requirements are necessary.
No
While we don't necessarily have an issue with the equipment owner communicating these relay limited circuits to the Regional Entities, we don't believe this is needed for reliability and therefore it should not be included in the reliability standard. Given that it is unclear what the information will even be used for, if it will be needed long-term, and that it is likely will not change much, if at all, from year to year, we believe a data request through NERC's Rules of Procedure section 1600 would be more appropriate. In that way, we don't have to modify the standard later when NERC and the Regions determine they don't need the data annually.
No
It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV that are part of the Bulk Electric System. This information is not readily available and there is no requirement for the Regional Entity to communicate it to them. Thus, inaction by the auditor (i.e. Regional Entity) could actually cause the Planning Coordinator to violate this requirement. This is clearly a conflict of interest. Why does the Planning Coordinator need to identify which circuits are identified per criteria B4? There is no justification given for this need and there is nothing else that appears to require action as a result of this information. Thus, it is purely administrative and should be removed. Registered entities should never be subject to potential sanctions for violations of purely administrative portions of requirements. Why does the Planning Coordinator need to provide this information to the Reliability Coordinator? There is nothing for the Reliability Coordinator to do with the information. The Reliability Coordinator only needs to be informed if equipment becomes derated and then that should occur through the normal communication of ratings per FAC-009-1.
No
We do not believe that R7 is needed. The applicability section of the standard is clear that the standard applies to those circuits identified in R6. This requirement could be construed as potential for double jeopardy because failure to comply with Requirements 1 through 5 would represent a violation of both Requirement 7 and Requirements 1 through 5.
Yes
No
While we appreciate the drafting team's effort to refine the flowgate criteria from the last posting, the modifications do not go far enough and still do not reflect the use of flowgates. NERC's definition of flowgate includes two components. Let's focus on the first component which represents those flowgates defined in the IDC. Because IDC flowgates list is updated monthly and the IDC users can add temporary flowgates to the IDC at any time, this is an inappropriate list to use. We appreciate the drafting team's attempt to resolve this issue by including the caveat "that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator." However, this really only confuses the matter and does not solve it. Reliability Coordinators add flowgates to manage real-time congestion. Planning Coordinators do not. Per the NERC functional model, they do not even have a role in deciding which flowgates to add to the IDC. Flowgates are added to the IDC to mitigate existing, known congestion points not congestion points identified in a long-term planning study that may never materialize due to changing conditions. Thus, IDC flowgates should be specifically excluded. Now let us focus on the second component of flowgate. The second component is much like the first component in that is it a mathematical construct to analyze the impact of power flows on the BES except is not required to be included in the IDC. There is nothing in the definition of a flowgate to give credence that is represents anything more that point to calculate power flows and the impact of transactions. Flowgates are primarily used to manage congestion on the system and to sell transmission system. Because it is convenient to select a group of lines as a proxy to sell transmission service or manage congestion does not mean that those group of lines represent a reliability issue. Thus, we do not believe any flowgates should be included in the list. Any true reliability issues can be identified through the TPL studies and those facilities that do not meet the performance requirements are what should be used. We do not support criterion B4. It exceeds what is required in the TPL standards and what is required per the reliability directive in Order 729. The TPL standards allow system operator intervention for category C3 contingencies between the two independent Category B contingencies. This standard should not exceed those requirements in the TPL standards. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test "must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning." Paragraph 80 states that "the test must be consistent with the general reliability principles embedded in the existing series of TPL" standards. Thus, exceeding the TPL standards could be argued as deviating from the directive. In response to comments that did not support this criterion during the first posting, the standards drafting team responded with "Testing multiple element contingencies while accounting for system adjustments between each element outage will not yield any facilities to be subject to PRC-023 as long as TPL-003 system performance requirements are met." We think the drafting team missed a basic point about the standard. The issue is not whether the registered entity develops and documents corrective actions plans per TPL-003-0a R2 and R3. The issue is if the system as currently designed meets the performance requirements in TPL-003-0a R1 which allows for operator interventions on Category C3 contingencies. For those C3 contingencies that don't currently meet the performance obligations after operator interventions, the subject facilities would be included PRC-023-2 R6 list of facilities.
Individual
Joe Knight
Great River Energy
Yes
Yes

No
We do not believe this requirement is needed. Limiting a relay setting to 115% of the associated transmission line's highest seasonal 15 minute rating does not equate to a line that will trip before the operator has time to intervene. It does not mean the line will trip in 15 minutes. In fact, the operator should be taking action well in advance of reaching a 15 minute limit and the operator is likely only using the 15 minute rating in extreme circumstances. Furthermore, PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings including those limited by relays. As a result, neither PRC-023-2 R3 nor R4 is even needed. We assume the drafting team must be aware of these FAC standard requirements because they did not even require reporting to the Reliability Coordinator, Planning Coordinator and Transmission Operator of those circuits that are actually limited by the relay per criterion 12. We agree that FAC-008-1 and FAC-009-1 collectively establish the necessary requirements to compel the Transmission Owner and Generator Owner to communicate these relay limited circuits and that no additional requirements are necessary.
No
While we don't necessarily have an issue with the equipment owner communicating these relay limited circuits to the Regional Entities, we don't believe this is needed for reliability and therefore it should not be included in the reliability standard. Given that it is unclear what the information will even be used for, if it will be needed long-term, and that it is likely will not change much, if at all, from year to year, we believe a data request through NERC's Rules of Procedure section 1600 would be more appropriate. In that way, we don't have to modify the standard later when NERC and the Regions determine they don't need the data annually.
No
It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV and that are part of the Bulk Electric System. This information is not readily available and there is no requirement for the Regional Entity to communicate it to them. Thus, inaction by the auditor (i.e. Regional Entity) could actually cause the Planning Coordinator to violate this requirement. This is clearly a conflict of interest. Why does the Planning Coordinator need to identify which circuits are identified per criteria B4? There is no justification given for this need and there is nothing else that appears to require action as a result of this information. Thus, it is purely administrative and should be removed. Registered entities should never be subject to potential sanctions for violations of purely administrative portions of requirements. Why does the Planning Coordinator need to provide this information to the Reliability Coordinator? There is nothing for the Reliability Coordinator to do with the information. The Reliability Coordinator only needs to be informed if equipment becomes derated and then that should occur through the normal communication of ratings per FAC-009-1
No
We do not believe that R7 is needed. The applicability section of the standard is clear that the standard applies to those circuits identified in R6. This requirement could be construed as potential for double jeopardy because failure to comply with Requirements 1 through 5 would represent a violation of both Requirement 7 and Requirements 1 through 5.
Yes
No
While we appreciate the drafting team's effort to refine the flowgate criteria from the last posting, the modifications do not go far enough and still do not reflect the use of flowgates. NERC's definition of flowgate includes two components. Let's focus on the first component which represents those flowgates defined in the IDC. Because the IDC flowgates list is updated monthly and the IDC users can add temporary flowgates to it at any time, this is an inappropriate list to use. We appreciate the drafting team's attempt to resolve this issue by including the caveat "that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator." However, this really only confuses the matter and does not solve it. The Reliability Coordinator adds flowgates to manage real-time congestion. The Planning Coordinator does not. Per the NERC functional model, they do not even have a role in deciding which flowgates to add to the IDC. Flowgates are added to the IDC to mitigate existing, known congestion points not congestion points identified in a long-term planning study that may never materialize due to changing conditions. Thus, IDC flowgates should be specifically excluded. Now let us focus on the second component of flowgate. The second component is much like the first component in that it is a mathematical construct to analyze the impact of power flows on the BES except it is not required to be included in the IDC. There is nothing in the definition of a flowgate to give credence that it represents anything more that point to calculate power flows and the impact of transactions. Flowgates are primarily used to manage congestion on the system and to sell transmission system. Because it is convenient to select a group of lines as a proxy to sell transmission service or manage congestion does not mean that those group of lines represent a reliability issue. Thus, we do not believe any flowgates should be included in the list. Any true reliability issues can be identified through the TPL studies and those facilities that do not meet the performance requirements are what should be used. We do not support criterion B4. It exceeds what is required in the TPL standards and what is required per the reliability directive in Order 729. The TPL standards allow system operator intervention for category C3 contingencies between the two independent Category B contingencies. This standard should not exceed those requirements in the TPL standards. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test "must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning." Paragraph 80 states that "the test must be consistent with the general reliability principles embedded in the existing series of TPL" standards. Thus, exceeding the TPL standards could be argued as deviating from the directive. In response to comments that did not support this criterion during the first posting, the standards drafting team responded with "Testing multiple element contingencies while accounting for system adjustments between each element outage will

not yield any facilities to be subject to PRC-023 as long as TPL-003 system performance requirements are met." We think the drafting team missed a basic point about the standard. The issue is not whether the registered entity develops and documents corrective actions plans per TPL-003-0a R2 and R3. The issue is if the system as currently designed meets the performance requirements in TPL-003-0a R1 which allows for operator interventions on Category C3 contingencies. For those C3 contingencies that don't currently meet the performance obligations after operator interventions, the subject facilities would be included PRC-023-2 R6 list of facilities.
Group
Santee Cooper
Terry L. Blackwell
Yes
No
We appreciate the drafting team addressing this issue, and, in general, agree with our understanding of the intention of this requirement. However, the wording of the section should be a little clearer. Through asking questions about the intention of these statements, it is our understanding that, as long as the composite scheme (made up of all the relay elements protecting the transmission line) will still operate for a fault in a time that is compliant with the TPL standards, that this requirement is met. This may mean that a particular relay element may still be blocked, but there are other relay elements, possibly with a different time delay, that would still operate in an appropriate amount of time. As long as the total scheme protecting the element in question still meets all of the TPL and stability requirements for isolating the fault from the system, the operation of the scheme should be satisfactory. If this is still the intention, then it should be clarified in this requirement.
Yes
Yes
Yes
Yes
Yes
No
The criteria in Attachment B lack clarity. For example, B4 criteria for powerflow analysis does not specify a horizon. In addition, in B1 does that only apply to circuits that are monitored by you or the IDC? Assessing the post-contingency loading and determining if a facility rating is based on loading durations of specified time periods is too burdensome and would not provide much value.
Individual
Dan Rochester
Independent Electricity System Operator
No
Clarification is needed on whether criterion 10 requires a transformer to have load responsive protection to protect from mechanical damage. The wording in criterion 10 should be changed to "set transformer fault protection relay or transmission line relay on transmission line terminated with only a transformer." Is this criteria requiring that a transformer with only differential protection and no other load responsive remote protection be mitigated with additional load responsive protection?
Yes
No
As indicated in our previous comments, the FERC Directive asks for provision of this information to the TOP only. We question the need to go beyond what's being asked for in the Directive to require the responsible entities to provide this information to other entities (PC and RC). If a reliability need is not identified, we suggest that these two entities be removed from the requirement.
Yes
No
We agree that the PC should be held responsible for conducting the annual assessment, but we do not understand the need for including "if the Regional Entity has identified either of these Element types as critical facilities for the purposes of the Compliance Registry" in R6.2. We also do not understand the meaning of "as critical facilities for the purpose of Compliance Registry". There are established criteria for compliance registry, but we are not aware of what constitutes "critical facilities for the purpose of compliance registry". For the purpose of determining compliance with the relay loadability requirements, having the PC to make such an assessment and determination would suffice. If the intent is to limit the facilities to be assessed to only those that have been identified as "critical facilities for the purpose of compliance registry", then it implies that those that are not identified are not required to be assessed. This may in fact result in missing some facilities that may be critical from a relay loadability standpoint. Further, the term "critical facilities" is used very loosely in different standards, and can mean very different things for various applications and under various

circumstances. We suggest to remove ““if the Regional Entity has identified either of these Element types as critical facilities for the purposes of the Compliance Registry” from the requirement. For the same reason, we suggest the quoted phrase be removed from the Applicability Section, any other requirements in this standard, and Attachment B.
Yes
No
We commented on Criterion 6 (now B4) related to TPL-003 Category C contingencies in the previous posting but we see no evidence that our comment was addressed. We therefore reiterate our position. The PC and TP assess their future systems according to the performance requirements stipulated in the TPL standards, including those in TPL-003. We question the requirement to have Planning Coordinators assess the impact of double contingencies with no manual system adjustments in between since this is not required by TPL-003. This goes beyond the basic planning and design requirements and in our view should be removed from Criterion B4. We also believe Criterion B4 should be rewritten for greater clarity. The second bullet seems unnecessary since the post contingency loading on each circuit will not in fact be compared against its Facility Rating to determine applicability of PRC-023-2 but against the corresponding “applicability threshold”. Also, the third bullet seems to conflict with the fourth, since the forth bullet allows for determining thresholds based on Facility Ratings that assume various loading durations, whereas the third bullet links determination of the threshold to the Facility Rating for a duration nearest four hours only. We therefore suggest the following alternative wording for B4: B4. Each circuit operated between 100 kV and 200 kV identified by applying the following procedure: B4.1Establish Thresholds of Applicability – (text of 4th bullet of B4) B4.2 Conduct Analysis – Conduct power flow analysis to simulate double contingency combinations selected by engineering judgment as indicated in TPL-003 Category C3. B4.3 Evaluate Applicability of PRC-023-2 – Compare post contingency loading of each circuit against its corresponding threshold determined in B4.1. Indicate the applicability of standard PRC-023-2 to each circuit for which the post contingency loading exceeds the corresponding threshold. B4.4 Exclusion - Radial circuits serving only load are excluded.
Group
Bonneville Power Administration
Denise Koehn
No
BPA believes that FERC does not fully understand how transformers are rated and applied on the Bulk Electric System. Therefore, we believe the concern they expressed in their NOPR and Order 733 regarding the reliability of the Bulk Electric System being jeopardized by operating a transformer at 150% of its nameplate rating is unfounded. In response to FERC’s concern, NERC has modified Criterion 10, which now has two conflicting requirements—ensuring that there is no operation for one level of load and ensuring that there is operation for another level of load. In some cases, these two load levels overlap and both requirements cannot be achieved simultaneously. The requirement in Criterion 10 that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability is ambiguous. It is not clear how the mechanical withstand capability is to be determined. IEEE Standard C57.109 provides recommended transformer through-fault duration limits, but these do not represent the actual mechanical withstand capability of transformers. IEEE Standard C57.12.00 specifies that transformers shall be designed and constructed to withstand the mechanical and thermal stresses produced by a fault limited only by the transformer impedance, or for category III and IV transformers, transformer impedance plus system impedance, for a duration of two seconds. However, the standard specifies that for currents between rated current and maximum short-circuit current the allowable time duration should be obtained by consulting the manufacturer. These standards do not clearly indicate what the mechanical withstand capability of transformers are. Certainly, for many existing transformers, there is no available manufacturer’s data for this either, and it is unclear how to comply with Criterion 10. BPA feels this is too ambiguous and exposes entities to an unnecessary risk of possibly being sanctioned based on the judgment of an auditor. BPA believes that FERC’s concern about transformer damage at the loading levels addressed by this standard is unfounded and contradictory to the purpose of this standard. The purpose of PRC-023 is to prevent automatic relay operations--which could cause cascading outages and quickly deteriorate the reliability of the BES--during severe system loading conditions. Under these loading conditions it is desirable that system operators have time to take corrective action to mitigate system problems before automatic relay operations accelerate the problem into a blackout. IEEE Standard C57.109 indicates that transformers can sustain 200% of rated load for at least thirty minutes. If relays are set to operate in this range, they are at risk of tripping a transformer under emergency loading situations, which exasperates the very problem that PRC-023 is attempting to eliminate. Most utilities have developed emergency ratings for their transformers. When a transformer load exceeds a predetermined level, the system operators are alarmed so that they can take appropriate action. During stressed system conditions, allowing a critical transformer to operate up to these emergency ratings could prevent a blackout. Conversely, requiring relays to be set in this range could result in the automatic loss of critical transformers, thereby accelerating the collapse of the bulk electric system. The ability of transformers to carry load without thermal damage or with acceptable levels of loss of life has been under study for many decades. There are many variables, such as ambient temperature, duty cycle, acceptable loss of life, etc., that determine the load and duration that a transformer is capable of. It has been addressed in transformer design and relay protection standards. Many utilities have made considerable efforts to determine the appropriate levels of emergency loading for their transformers. The mechanical withstand capability of a transformer is not the relevant factor at the load levels addressed by PRC-023. BPA is concerned that we might be on the verge of superseding these many decades of research and experience with a poorly written, ambiguous, and inapplicable requirement because of the misunderstanding of the FERC commissioners. BPA suggests that NERC resist FERC’s demands for setting relays to operate within the emergency operating capabilities of transformers. Additionally, BPA believes that there is no reason for FERC to be concerned with transformer overload protection. There is not a widespread problem with transformers being overloaded, and placing requirements on the industry for transformer protection results in an increased burden and expense to the industry with no resulting benefits. The subject of transformer loading has gained FERC’s attention only as a result of its inclusion in PRC-023, and is not a problem for the BES—mostly because the industry has done the opposite of what FERC is now asking and not set transformer relays to operate in the emergency loading region. If transformer protection were an issue, it would be worthy

of an individual standard, separate from PRC-023, because it is too complex to address in a short paragraph such as Criterion 10. Finally, BPA believes that Requirement 1 is unclear. It states that each TO, GO, and DP shall use any one of the 13 criteria for any specific circuit terminal to prevent its phase protective relays from limiting transmission loadability. Does this mean that the requirements of Criterion 10 only apply if Criterion 10 is used as the basis for justifying the relay settings of a terminal? If the relay settings for a transformer-terminated line are justified by one of the other criteria, say Criterion 1, is an entity allowed to ignore the requirements of Criterion 10 for the transformer overcurrent relays? Are transformer relays for transformers that aren't part of a transformer-terminated line subject to Criterion 10? BPA recommends that the words "such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability" be removed from Criterion 10. In addition, if all transformer overcurrent relays—not just those for transformer-terminated lines—are subject to the requirements of Criterion 10 (as suggested by Attachment A), they need to be addressed in a separate requirement because the 13 criteria of Requirement 1 are not necessarily mandatory.
Yes
No
BPA does not understand why a list of such facilities must be provided each year. These facilities will not change very often, and a new list should only be required when changes are made to the old list. Please explain why you feel it is necessary.
No
Since a Registered Entity is already required to obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator and to use the calculated circuit capability as the Facility Rating of the circuit as required by R3, BPA would like additional information regarding the purpose of providing the Regional Entity a list each year. What would they do with the list?
No
BPA feels the applicable date descriptions are too confusing and would like to see more clarity and simplification.
Yes
No
The evaluation method seems technically sound. The second category of applicable circuits, "Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV ...", are not considered BES elements based on the latest definition and BPA does not believe that this category of circuits should be included.
Individual
Michael R. Lombardi
Northeast Utilities
No
Further clarification is needed for this criterion. Is it the intention of this criterion that all applicable transformers must have load responsive protection to prevent mechanical damage from a through fault? If load responsive protection for the transformer element does not presently exist, i.e. only differential protection exists for the transformer element, will load responsive transformer protection have to be added to comply with this criterion? It is also suggested that R1 Criterion 10 wording be changed to "Set transformer fault protection relays or transmission line relays on transmission lines terminated only with a transformer to ……." since it appears from the NERC Webinar on 11/23/10 that the intention was address the possible locations where phase protection for the transformer could exist and not infer that this protection was needed at both locations.
No
What is the expectation for verification that the out-of-step blocking elements allow tripping of phase protection relays for faults that occur duing the loading conditions used to verify transmission line relay loadability? It would be very costly and time consuming to verify proper operation of these blocking schemes for all of the various possible fault and loading combination scenarios for each application of this scheme.
Yes
Suggest clarification for Section 4.2.6 be added. That is, our review of the draft indicates that, as its title implies, this Standard primarily focuses on transmission relaying for lines and transformers. Nowhere does it mention generation relaying, per se, and the transformer relaying appears to be focused on "transmission" transformers and other transformers that have bi-directional flow capability. There is one sticking point, however. Section 4.2.6 seems to muddy the otherwise clear "transmission" directive in that it extends the applicability to: "4.2.6 Transformers with low voltage terminals connected below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry and the Planning Coordinator has determined are required to comply with this standard". While we believe that this was intended to pertain to transmission or load-serving transformers, due to ambiguity in the Standard this could be taken to mean transformers in facilities deemed "material to the reliability of the Bulk Power System." It could thus be applied (incorrectly, in our opinion) to generation facilities. We would also question why there would be a concern for the low voltage side of a GSU. Please clarify Section 4.2.6, as appropriate.
Yes
Yes
Yes

Yes
Yes
Individual
Armin Klusman
CenterPoint Energy
No
CenterPoint Energy disagrees with providing a list to Planning Coordinators, Transmission Operators, and Reliability Coordinators, as we cannot see any need and do not expect these entities would utilize this information in any manner.
No
CenterPoint Energy disagrees with providing a list, as we cannot see any need and do not expect the Regional Entity would have any use for this information. In discussions with Regional Entity personnel, they were unsure of what use they would have for this information.
No
(a) CenterPoint Energy recommends revising R6 to require Planning Coordinators to coordinate with associated Transmission Planners in the determination of which 100 – 200 kV elements must comply with this standard. (b) CenterPoint Energy recommends criterion B5 be deleted, as it is too broad and gives the Planning Coordinator too much discretion in determining other facilities which must comply with this Standard. In the case that criteria B5 is not deleted, CenterPoint Energy recommends that a process be required where Transmission Planners can appeal the inclusion of specific Transmission elements that must comply with this standard. (c) CenterPoint Energy recommends eliminating the un-capitalized term “critical” to remove any confusion with NERC CIP reliability standards. The voluntary NERC relay loadability review in 2006 used the term “operationally significant element” for elements 100 – 200 kV. CenterPoint Energy recommends using “operationally significant” wherever “critical” is used within PRC-023-2.
No
CenterPoint Energy believes Requirement 7 should be deleted from PRC-23-2, as it an Effective Date / Implementation Plan issue. Instead the wording should be included in PRC-023-2 in Effective Dates item 5.5 and within the Implementation Plan.
No
(a) Criterion B3 indicates any path that is used to supply off-site power to nuclear plants, as agreed to by the plant owner and the Transmission Entity. If the purpose of attachment B is to provide “bright line” criteria, then a negotiated agreement would not qualify as “bright line”. Additionally, off-site power requirements are meant to ensure safe shutdown of nuclear reactors in a system restoration event where transmission lines are lightly loaded. CenterPoint Energy recommends criterion B3 be deleted. (b) Considering situations where the transmission system may be at risk of cascading outages or voltage collapse, sub-200 kV elements should be considered operationally significant only whenever reasonably contemplated scenarios would cause high amperage and low voltage to be experienced on the elements. Criteria B4.a in Attachment B proposes loading exceeding 115% of a two or four hour rating following a double contingency, without manual system adjustments. CenterPoint Energy believes this is not a technically sound method to indicate if an element is operationally significant.
Group
New York Power Authority
Bruce Metruck
No
Clarification is needed on whether criterion 10 requires a transformer to have load responsive protection to protect from mechanical damage, either from internal faults, or through faults. If load responsive protection for the transformer element does not presently exist, i.e. only differential protection exists for the transformer element, will load responsive transformer protection have to be added to comply with this criterion? The wording in criterion 10 should be changed to “Set transformer fault protection relays or transmission line relays on transmission lines terminated only with a transformer to …….” Is this criteria requiring that a transformer with only differential protection and no other load responsive remote protection be supplemented with additional load responsive protection? The loading on phase angle regulators, and series reactors should be considered and mentioned. Also, there appears to be words missing in criterion 9 of R1: “the maximum current flow from the ? to the ? under any system configuration.” From the NERC Webinar on 11/23/10 the intention was to address the possible locations where phase protection for the transformer could exist and not imply that this protection was needed at both locations.
Yes
Yes
Yes
Yes

Yes
Yes
No
B2. Item B2 adds significant confusion to the process. The long term planning horizon may include transmission projects which have not even been built or alternative system configurations which do not exist, making it impossible for affected parties to set their relays appropriately. Suggested replacement language to avoid this issue: “Each circuit that is a monitored element of an IROL, assuming that all transmission elements are in service and the system is under normal conditions.” B3. This item indicates that the circuits to be considered are to be agreed to by the plant owner and the Transmission Entity. Attachment B is applicable to the Planning Coordinator. If this item is by agreement by the plant and the Transmission Entity it should be removed from Attachment B and placed elsewhere in the document. If this is intended to apply to the Planning Coordinator, Transmission Entity should be replaced with Planning Coordinator. Why does B3 only apply to Nuclear Power Plants? B4. This criterion is overly stringent and should be deleted. The system is neither planned nor operated to allow for two overlapping outages without operator action in between. If this criterion is retained, it should be made consistent with the requirements of TPL-003 where operator actions can be assumed between the first and second contingencies. Since a similar comment was made previously, more information is being provided following. 1. Since the system is neither planned nor operated to two overlapping outages in between, such testing may result in unsolved cases, or voltages well below criteria. In the case of an unsolved case, there are no flows to evaluate, making this standard impossible to apply. In the case of a solved case with voltages well below criteria, currents are likely to be incredibly high and therefore viewed as unrealistic. These concerns may limit the contingency selection to those which are not severe, eliminating any perceived benefit from this testing. 2. There is no guidance provided on how the system should be dispatched in the model upon which the overlapping contingencies are tested. This will result in significant discrepancies between the base assumptions used by the various Planning Coordinators. The contents of this standard should be reviewed to reflect the new definition of the Bulk Electric System.
Group
FirstEnergy
Doug Hohlbaugh
No
Criterion 10 does not take bidirectional load flow into consideration which could compromise the entity’s ability to provide backup protection for the transmission system. We suggest the following wording for criterion 10: “Set transformer fault protection relays and transmission line 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 and 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 for load flow from the normal source side to the normal load side. ♣ 115% of the highest operator established emergency transformer rating for load flow from the normal source side to the normal load side. ♣ 115% of the maximum current flow from the normal load side to the normal source side under any system configuration.” We also ask that the team consider similar wording be added to Criterion 11 as suggested above for consistency with Criterion 10. Criterion 9 seems to be missing some words in the phrase “flow from the to the under any system configuration”. It appears this should say “from the load to the system under any system configuration.”
Yes
Yes
No
FE recognizes that the standard drafting team introduced Requirement R5 in response to a FERC directive requiring NERC to document and make available upon request a list of protective relays set pursuant to Requirement R1, Criterion 12. We commend FERC in their Order 733 decision to retain Criterion 12 over accepting the preceding NOPR recommendation to remove it and support FERC’s desire in making information readily available on entities application of Criterion 12 for its own use and other interested parties. We are not opposed to providing our Regional Entity the information desired but believe this presents an administrative task that can be accomplished outside of a mandatory and enforceable reliability requirement. Since the reported data is for informational purposes and not a reliability need, we encourage the drafting team propose to NERC staff an equally efficient and effective alternative of having the Regional Entity periodically obtain the data through NERC’s Rules of Procedure, Section 1600 titled “Request for Data or Information”.
Yes
While we agree with the intent of Requirement R6, FE believes improvements can be made to simplify and clarify the R6 text. a. Items 6.1 and 6.2 can be removed as they are duplicative with the two bulleted items listed at the forefront of Attachment B. b. Item 6.3 is awkwardly written based on the circular reference to R6. Its suggested that Item 6.3 be re-written to say “Maintain a list of transmission Facilities operated below 200kV and deemed applicable to the PRC-023 standard per application of Attachment B” c. Requirement R6 and Attachment B text seem to mix and interchange references to Glossary of Term definitions “Elements” and “Facility”, although facility(ies) is often not capitalized, such that they are used synonymously. As one example R6 indicates “…determine which transmission Elements must comply with this standard …” compared to Attachment B which says “… to determine the facilities which must comply with this standard.” Sub items of R6 refer to keeping a list of “facilities” and not “Elements” as referenced in the parent R6 requirement. For greater consistency we suggest the use of the term “Facility(ies)” over “Element”. d. If the team believes a reference to a Planning Coordinator only needing to cover transmission facilities within their footprint is needed, such as

used in items 6.1 and 6.2 which are proposed for removal, the team could revise the parent R6 text to read " … to determine which transmission Elements [Facilities] in its Planning Coordinator area must comply with this standard." e. Replace the word "year" in item 6.5 with "planning study year". Its also recommended that the same change occur in R7, to better clarify what "year" is referring to in R7.
Yes
We support the minimum 24 month implementation timeframe because a responsible entity will need sufficient time to allow for any capital expenditures that may be required due to additional facilities identified by the Planning Coordinator.
Yes
No
FE proposes that criterion B1 be removed from Attachment B. We support criterion B3 as written and proposed revised versions of criterion B2 and B4. a. Item B1 implies all facilities operated below 200kV and associated with a Flowgate must comply with the PRC-023 standard. We support both MISO's and PJM's view that this criterion should be removed since Flowgates in their truest sense is used for economic and market transmission needs over reliability needs. Flowgates describe a designated point on the transmission system through which the Interchange Distribution Calculator (IDC) calculates the power flow from Interchange Transactions. While its recognized the drafting team attempted improve the Flowgate criteria by including a statement "that has been included to address a long-term reliability concerns, as confirmed by the applicable Planning Coordinator", it is FE's opinion that a Planning Coordinator does not play a role in adding or revising Flowgates used in the IDC and do not utilize Flowgates for long-term reliability planning purposes. Flowgates are a means of managing congestion and for identifying available transfer capability. Continued use of this criterion will only serve to confuse and complicate matters. b. Item B2 should be revised to include not only the monitored facilities associated with the IROL, but also any "contingent" facilities that may describe the IROL condition. For example, it is important to include the transmission facilities described in a NERC C3 contingency that may be associated with an IROL definition. A C3 contingency describes a N-1-1 condition with system adjustments permitted in between the 1st and 2nd contingency. It is necessary to ensure that the 2nd contingent facility does not prematurely trip due to a relay loadability limitation. For greater consistency with terminology used in the FAC-014 standard, Requirement R5.1 we propose the following for criterion B2: "B2. Each circuit monitored as critical to the derivation of an IROL and each circuit associated with the Contingency(ies) that describe the need for the IROL." c. We support criterion B3 as written. d. In regards to criterion B4, FE supports the team's recommendation for the Planning Coordinator to perform a modified NERC Category C3 analysis to further identify sub 200kV facilities applicable to the PRC-023 standard. However, the sub-bullets identifying various loading thresholds depending on the Facility rating is overly complicated and creates undue burden for the Planning Coordinator performing the study. We propose that the team simplify this criterion to clarify the applicable facilities are those that exceed 130% of their continuous emergency rating for the modified NERC Category C3 test.
Individual
Gregory Campoli
New York Independent System Operator
Yes
No comment from the PC & RC perspective, the TOs are responsible for designing phase protection schemes appropriate to their systems
No
PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1, and therefore unnecessary. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings including those limited by relays.
Yes
No
Wording for R6.2 is confusing. It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV. This information is not readily available and there is no requirement for the Regional Entity to communicate it to them. Revise to clearly state the intent of the requirement is for registered entities to report to Regional Entities those applicable facilities below 100kV and that the requirement for Regional Entities is only to make that list available. There is no justification given in R6.4 for the need to identify facilities for which criterion B4 applies and there is no further required action as a result of this information. Thus, it is purely administrative and should be removed. Registered entities should never be subject to potential sanctions for violations of purely administrative portions of requirements.
No
R7 is unnecessary as the applicability section of the standard is clear that the standard applies to those circuits identified in R6. This requirement could be construed as potential for double jeopardy because failure to comply with Requirements 1-5 represents a violation of both Requirement 7 and Requirements 1-5.
Yes
No
Flowgates are primarily used to manage congestion on the system and to sell transmission system. Because it is convenient to select a group of lines as a proxy to sell transmission service or manage congestion does not mean that those group of lines represent a reliability issue. Thus, flowgates should not be included in the list as currently specified in

B1. Any true reliability issues can be identified through the TPL studies and those facilities that do not meet the performance requirements are what should be applicable here. B2 adds significant confusion to the process. The long term planning horizon may include transmission projects which have not even been built or alternative system configurations which do not exist, making it impossible for affected parties to set their relays appropriately. Suggested replacement language to avoid this issue: “Each circuit that is a monitored element of an IROL, assuming that all transmission elements are in service and the system is under normal conditions.” B3 indicates that the circuits to be considered are to be agreed to by the plant owner and the Transmission Entity. Attachment B is applicable to the Planning Coordinator. If this item is by agreement by the plant and the Transmission Entity it should be removed from Attachment B and placed elsewhere in the document. If this is intended to apply to the Planning Coordinator, Transmission Entity should be replaced with Planning Coordinator. The B4 criterion is overly stringent and should be deleted. The system is neither planned nor operated to allow for two overlapping outages without operator action in between. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test “must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning.” Paragraph 80 states that “the test must be consistent with the general reliability principles embedded in the existing series of TPL” standards. If this criterion is retained, it should be made consistent with the requirements of TPL-003 where operator actions can be assumed between the first and second contingencies.
Individual
Darryl Curtis
Oncor Electric Delivery Company LLC
No
In paragraph 209 of Order No 733 it states: Since Requirement R1.10 applies to any topology, it must be robust enough to address the reliability issues of any topology. In light of the above statement criterion 10 of Requirement R1 should be modified to read as follows: Set transformer fault protection relays and transmission line relays used for transformer fault protection such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability and so that the relays do not operate at or below the greater of: By eliminating the special topology of “transmission lines terminated only with a transformer” from criterion 10 it eliminates any ambiguity that the criterion only applies to special transmission line cases and complies with the FERC assertion that the Requirement “applies to any topology.” Oncor like other Transmission Owners provides autotransformer protection from possible thermal damage due to either prolonged through faults or load with its transformer overload protection relays. Protection of all autotransformers from fault level and duration that exceeds their mechanical withstand capability is provided by the redundant phase and ground relay settings of the local zones of protection coupled with local breaker failure protection. For prolonged faults that are outside the local zones of protection (not threatening damage to the transformer by exceeding the mechanical withstand capability of the transformer) or where loads exceed the thermal rating of the transformer the phase and ground transformer overload protection relays protect the transformer from thermal damage. Based on the fact that at many locations a transformer is protected by local Protection Systems from prolonged “Close in” phase and ground through faults that might be within the fault level and duration that exceeds their mechanical withstand capability, criterion 11 of Requirement R1 should be modified as follows: For transformer overload protection relays that do not comply with the loadability or mechanical withstand capability components of Requirement R1, criterion 10 set the relays according to one of the following: If transformer protection from fault level and duration that exceeds a transformer’s mechanical withstand capability is provided by other Protection Systems, set the transformer overload protection settings to not expose the transformer to current level and duration that exceeds its thermal withstand capability and 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 or 115% of the highest operator established emergency transformer rating. 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. Oncor believes that criterion 10 of Requirement R1 needs to be further modified as stated above to ensure that it applies to transmission lines of any topology and not just to transmission lines terminated only with a transformer. Oncor also feels that modifying criterion 10 of Requirement R1 by adding a requirement to ensure that protection settings do not expose transformers to fault level and duration requires that, for the reasons stated above, criterion 11 of Requirement R1 must be modified as noted above.
Yes
No
Oncor feels that the Requirement R4 is too cumbersome for the Registered Entities who have to, every 12 to 15 months, provide to the Planning Coordinator, Transmission Operator and Reliability Coordinator massive amounts of information that rarely changes. Also by allowing up to 15 months between reports to the Planning Coordinator, Transmission Operator and Reliability Coordinator of relay setting changes made by Registered Entities these Operators and Coordinators are deprived of knowing changes to loading limitations for up to 15 months. To overcome the problems with Requirement R4 of the present version PRC-023-2 Oncor has two specific suggestions for improvement. First, Requirement R4 should be changed to have a one time requirement for 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 to provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with a list of facilities associated with those transmission line relays. Second, Requirement R4 should be changed to require 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 to provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with any changes (additions, deletions or modifications) to the one time list of facilities associated with those transmission line relays within 30 days changes are made to list. By using the proposed changes to R4 listed above, the

only information that needs be transferred between the Registered Entities and the Operators and Coordinators following the initial exchange of information are changes made to the initial information. By requiring the Registered Entities to notify the Operators and Coordinators shortly after changes are made the up to 15 month delay getting modifications to them is eliminated.
No
Oncor feels that the Requirement R5 is too cumbersome for the Registered Entities who have to, every 12 to 15 months, provide the Regional Entity a list of all the facilities that under Requirement R1 criterion 12 are limited by the requirement to adequately protect the transmission line and cannot meet loadablity. It would better for the Registered Entities to provide a one time list to its Regional Entity and then provide to the Regional Entity any additions or deletions to the list no more than 30 days following any changes to the relaying what would remove or add a transmission line to the list.
Yes
Yes
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
No
R1 - Clarification is needed on whether criterion 10 requires a transformer to have load responsive protection to protect from mechanical damage. The wording in criterion 10 should be changed to “set transformer fault protection relay or transmission line relay on transmission line terminated with only a transformer.” Is this criterion requiring that a transformer with only differential protection and no other load responsive remote protection be mitigated with additional load responsive protection? The loading on phase angle regulators, and series reactors should also be considered and mentioned. Also, there appears to be words missing in criterion 9 of R1: “the maximum current flow from the ? to the ? under any system configuration.”
No
R2 - What is the expectation for verifying that the out-of-step (OOS) blocking elements allow tripping of phase protection relays for faults that occur during the loading conditions used to verify transmission line relay loadability? It would be costly and time consuming to verify this. To comply with this requirement, utilities may have to remove OOS protections all together.
Yes
Yes
Yes
Yes
Yes
No
Attachment B - Why does B3 only apply to Nuclear Power Plants only?
Individual
Kirit Shah
Ameren
No
This additional statement is not necessary and already covered in R1 with the statement: ‘while maintaining reliable protection of the BES for all fault conditions.’
Yes
No
This requirement is redundant with Standards FAC-008-1 and FAC-009-1. The existing standards already cover ratings methodologies and reporting of facility ratings to the appropriate entities. In addition, these two standards already require consideration of relaying equipment as one component in developing ratings methodologies and in reporting of those ratings.
No
Given that protective relaying equipment is already covered as one component in developing ratings in standards FAC-008-1 and FAC-009-1, it is not clear that there is a reliability based need for the information required to be provided in Requirement R5. Therefore, this requirement should be removed from the proprosed standard.
No
Section 6.2 is unclear and seems arbitrary in the statement ‘if the Regional Entity has indentified either of these Element

types as critical facilities for the purpose of the Compliance registry'. A clear test is lacking.
No
As this requirement is structured, it creates a potential for double jeopardy should one of the other requirements mentioned (R1 through R5) be violated. This requirement is not needed and should be removed from the proposed standard.
No
Section 1.6 is contrary to section 2.0 and seems arbitrary. Why is a communication system for a current-based scheme treated to a higher standard than other communications scheme? The communications scheme reliability is covered through the maintenance and misoperations analysis standards.
No
Criterion B1, which has been modified to encompass only flowgates which have been included to address long-term reliability concerns, while a step in the right direction, does not go far enough. Because flowgates are primarily utilized to manage congestion and assist in the process of transmission service sales, rather than investigate reliability issues more appropriately conducted via study work covered under the TPL standards, this criteria should be eliminated. Criterion B4 as worded still exceeds the requirements of Reliability Standard TPL-003 by requiring simulating double contingencies with no operator intervention permitted. While such simulation would be done as part of assessment work under TPL-003 for fast-acting contingencies involving multiple circuits, such as Category C1 bus faults, C2 breaker failures, and C5 double-circuit tower outages, such simulations are not necessary under TPL-003 with Category C3 events which consist of separate Category B events with intervening operator action. Such simulations should not be made necessary as part of the proposed PRC-023-2 standard. Rather, should the TPL-003 performance requirements not be met for Category C3 contingencies with operator intervention considered, those facilities could be included in the list of facilities specified in PRC-023-2 Requirement R6.
Individual
Saurabh Saksena
National Grid
No
National Grid seeks clarification on whether criterion 10 requires transformer to have load responsive protection to protection from mechanical damage. The wording in criterion 10 should be changed to "set transformer fault protection relay or transmission line relay on transmission line terminated with only a transformer." For example, is this criteria requiring that a transformer with only differential protection and no other load responsive remote protection be mitigated with additional load responsive protection?
No
National Grid seeks clarification on what is the expectation for verifying that the out-of-step blocking elements allow tripping of phase protection relays for faults that occur during the loading conditions used to verify transmission line relay loadability? It would be costly and time consuming to verify this. To comply with this requirement, utilities may have to remove OOS protections all together.
Yes
Yes
Yes
Yes
Yes
No
1. As per Section 4.2.3 (also included as bullet point 2 of Applicable circuits in Attachment B) "Transmission Lines operated below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry and the Planning Coordinator has determined are required to comply with this standard." National Grid believes that voltage levels less than 100 kV are outside NERC's jurisdiction and hence, requirements related to sub 100 kV levels should not be part of NERC standards. 2. National Grid recommends a provision in the standard which allows entities an option to 1. Either comply with standard for all applicable elements or 2. Apply the methodology as stated in Attachment B. The rationale is that entities that choose to comply with PRC-023 for all applicable elements should be recognized and should be exempted from complying with the methodology in Attachment B. 3. Requirement R6 of the proposed standard requires entities to apply criteria in Attachment B and conduct assessments with no more than 15 months between assessments to determine which transmission elements must comply with this standard. TPL standard which is considered to be the primary standard dealing with designing and planning of the system allows an interim assessment to rely on previous years simulations and does not mandate a stringent 15 month period between assessments. National Grid believes that an auxiliary PRC-023 standard should not present more stringent requirements than the primary TPL standard and recommends to remove the "15 month between assessments" requirement.
Individual
Jeff Billo
ERCOT ISO
Yes

Yes
No
It is not clear what the Planning Coordinator and Reliability Coordinator is supposed to do with this information.
No
No
ERCOT ISO is unclear, as to what is meant by the reference to the Compliance Registry. Additionally, ERCOT ISO feels the Regional Entities are not the appropriate entities to declare which elements (below 100kV) should be considered critical. For 6.2 and Attachment B, ERCOT ISO suggests completely removing the existing language pertaining to facilities operated below 100kV.
Yes
Yes
No
In regards to criteria B1, the Texas Interconnection does not have comparable monitored elements. All transmission elements are treated and monitored equally in ERCOT at this time. The only exception to this is IROLs which are already covered in criteria B2. Therefore, ERCOT ISO suggests removing the reference to the Texas Interconnection in criteria B1. In regards to criteria B3, the Planning Coordinator does not necessarily know the circuit paths for off-site power for nuclear plants. The Transmission Owners would be better able to identify these circuits. ERCOT ISO suggests moving this criteria into section 4.2 (Applicability, Facilities). ERCOT ISO also suggests revising the language so that it does not state that a “circuit must comply with the standard” since it is an entity that must comply with the standard. ERCOT ISO suggests replacing this language with “circuit will be applicable to this standard” throughout Attachment B.
Individual
Terry Harbour
MidAmerican Energy
Yes
Yes
No
I don't believe this requirement is needed. Limiting a relay setting to 115% of the associated transmission line’s highest seasonal 15 minute rating does not equate to a line that will trip before the operator has time to intervene. It does not mean the line will trip in 15 minutes. In fact, the operator should be taking action well in advance of reaching a 15 minute limit and the operator is likely only using the 15 minute rating in extreme circumstances. Furthermore, PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings including those limited by relays. As a result, neither PRC-023-2 R3 nor R4 is even needed. We assume the drafting team must be aware of these FAC standard requirements because they did not even require reporting to the Reliability Coordinator, Planning Coordinator and Transmission Operator of those circuits that are actually limited by the relay per criterion 12. We agree that FAC-008-1 and FAC-009-1 collectively establish the necessary requirements to compel the Transmission Owner and Generator Owner to communicate these relay limited circuits and that no additional requirements are necessary.
No
While we don’t necessarily have an issue with the equipment owner communicating these relay limited circuits to the Regional Entities, we don’t believe this is needed for reliability and therefore it should not be included in the reliability standard. Given that it is unclear what the information will even be used for, if it will be needed long-term, and that it is likely will not change much, if at all, from year to year, we believe a data request through NERC’s Rules of Procedure section 1600 would be more appropriate. In that way, we don’t have to modify the standard later when NERC and the Regions determine they don’t need the data annually.
No
Sections 4.2.2, 4.2.3, 4.2.6, R6, and Attachment B needs to be modified with a superior alternative than the FERC recommendation to assign the PC the responsibility to determine a sub-200 kV critical facility test. NERC needs to re-assign this to the Transmission Owners and Operators as the entities that properly perform transmission planning analysis. The PC's aren't the proper entities that understand and perform the proper analyses. Therefore the superior alternative is to re-assign the responsibility to the party that understand what is truly critical and why. At a minimum Transmission Owners and / or Operators should be added to ensure that the entities that best understand the operation of the electric grid. It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV that are part of the Bulk Electric System. This information is not readily available and there is no requirement for the Regional Entity to communicate it to them. Thus, inaction by the auditor (i.e. Regional Entity) could actually cause the Planning Coordinator to violate this requirement. This is clearly a conflict of interest. Why does the Planning Coordinator need to identify which circuits are identified per criteria B4? There is no justification given for this need and there is nothing else that appears to require action as a result of this information. Thus, it is purely administrative and should be removed. Registered entities should never be subject to potential sanctions for violations of purely

administrative portions of requirements. Why does the Planning Coordinator need to provide this information to the Reliability Coordinator? There is nothing for the Reliability Coordinator to do with the information. The Reliability Coordinator only needs to be informed if equipment becomes derated and then that should occur through the normal communication of ratings per FAC-009-1.
No
We do not believe that R7 is needed. The applicability section of the standard is clear that the standard applies to those circuits identified in R6. This requirement could be construed as potential for double jeopardy because failure to comply with Requirements 1-5 for represent a violation of both Requirement 7 and Requirement 1-5.
Yes
No
Criterion B1 should be eliminated as there is no technical basis to show that "flowgates" are anything more than a measure of congestion. The loss or potential loss of a flowgate won't necessarily result in any more or less reliability impact to the BES than the loss of any other BES element. Therefore a superior criteria for Attachment B is to actually base critical elements upon the Federal Power Act Section 215 criteria of instability, uncontrolled separation, or cascading, which is related to the B2 criteria and being an IROL. Measuring the potential exceedance of TPL criteria as written is also acceptable. MidAmerican notes the NERC Attachment B criteria exceed the FERC directive to follow TPL criteria in Order 729.
Group
IRC Standards Review Committee
Ben Li
No
We do not believe this requirement is needed. Limiting a relay setting to 115% of the associated transmission line's highest seasonal 15 minute rating does not equate to a line that will trip before the operator has time to intervene. It does not mean the line will trip in 15 minutes. In fact, the operator should be taking action well in advance of reaching a 15 minute limit and the operator is likely only using the 15 minute rating in extreme circumstances. Furthermore, PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings including those limited by relays. As a result, neither PRC-023-2 R3 nor R4 is even needed. We assume the drafting team must be aware of these FAC standard requirements because they did not even require reporting to the Reliability Coordinator, Planning Coordinator and Transmission Operator of those circuits that are actually limited by the relay per criterion 12. We agree that FAC-008-1 and FAC-009-1 collectively establish the necessary requirements to compel the Transmission Owner and Generator Owner to communicate these relay limited circuits and that no additional requirements are necessary. Note: CAISO does not sign on to the above comments.
No
While we don't necessarily have an issue with the equipment owner communicating these relay limited circuits to the Regional Entities, we don't believe this is needed for reliability and therefore it should not be included in the reliability standard. Given that it is unclear what the information will even be used for, if it will be needed long-term, and that it is likely will not change much, if at all, from year to year, we believe a data request through NERC's Rules of Procedure section 1600 would be more appropriate. In that way, we don't have to modify the standard later when NERC and the Regions determine they don't need the data annually. Note: CAISO does not sign on to the above comments.
No
Wording for R 6.2 is confusing. Revise to clearly state the intent of the requirement is for registered entities to report to Regional Entities those facilities below 100KV that the requirements should apply to and that the requirement for Regional Entities is only to make that list available It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV that are part of the Bulk Electric System. This information is not readily available and there is no requirement for the Regional Entity to communicate it to them. Thus, inaction by the auditor (i.e. Regional Entity) could actually cause the Planning Coordinator to violate this requirement. This is clearly a conflict of interest. Why does the Planning Coordinator need to identify which circuits are identified per criteria B4? There is no justification given for this need and there is nothing else that appears to require action as a result of this information. Thus, it is purely administrative and should be removed. Registered entities should never be subject to potential sanctions for violations of purely administrative portions of requirements. Why does the Planning Coordinator need to provide this information to the Reliability Coordinator? There is nothing for the Reliability Coordinator to do with the information. The Reliability Coordinator only needs to be informed if equipment becomes derated and then that should occur through the normal communication of ratings per FAC-009-1. Note: CAISO does not sign on to the above comments.
No
We do not believe that R7 is needed. The applicability section of the standard is clear that the standard applies to those circuits identified in R6. This requirement could be construed as potential for double jeopardy because failure to comply with Requirements 1-5 for represent a violation of both Requirement 7 and Requirement 1-5.
Yes
No
We disagree with B1 which includes monitored elements of flowgates. Flowgates may not always be used for reliability

purposes and may be temporary to address certain economic conditions. While we appreciate the drafting team's effort to refine the flowgate criteria from the last posting, the modifications do not go far enough and still do not reflect the use of flowgates. NERC's definition of flowgate includes two components. Let's focus on the first component which represents those flowgates defined in the IDC. Because IDC flowgates list is updated monthly and the IDC users can add temporary flowgates to the IDC at any time, this is an inappropriate list to use. We appreciate the drafting team's attempt to resolve this issue by including the caveat "that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator." However, this really only confuses the matter and does not solve it. Reliability Coordinators add flowgates to manage real-time congestion. Planning Coordinators do not. Per the NERC functional model, they do not even have a role in deciding which flowgates to add to the IDC. Flowgates are added to the IDC to mitigate existing, known congestion points not congestion points identified in a long-term planning study that may never materialize due to changing conditions. Thus, IDC flowgates should be specifically excluded. Now let us focus on the second component of flowgate. The second component is much like the first component in that is it a mathematical construct to analyze the impact of power flows on the BES except is not required to be included in the IDC. There is nothing in the definition of a flowgate to give credence that is represents anything more that point to calculate power flows and the impact of transactions. Flowgates are primarily used to manage congestion on the system and to sell transmission system. Because it is convenient to select a group of lines as a proxy to sell transmission service or manage congestion does not mean that those group of lines represent a reliability issue. Thus, we do not believe any flowgates should be included in the list. Any true reliability issues can be identified through the TPL studies and those facilities that do not meet the performance requirements are what should be used. We do not support criterion B4. It exceeds what is required in the TPL standards and what is required per the reliability directive in Order 729. The TPL standards allow system operator intervention for category C3 contingencies between the two independent Category B contingencies. This standard should not exceed those requirements in the TPL standards. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test "must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning." Paragraph 80 states that "the test must be consistent with the general reliability principles embedded in the existing series of TPL" standards. Thus, exceeding the TPL standards could be argued as deviating from the directive. The directive is to be consistent not exceed. Exceeding the TPL standards is not consistency. In response to comments that did not support this criterion during the first posting, the standards drafting team responded with "Testing multiple element contingencies while accounting for system adjustments between each element outage will not yield any facilities to be subject to PRC-023 as long as TPL-003 system performance requirements are met." We think the drafting team missed a basic point about the standard. The issue is not whether the registered entity develops and documents corrective actions actions plans TPL-003-0a R2 and R3. The issue is if the system as currently designed meets the performance requirements in TPL-003-0a R1 which allows for operator interventions on Category C3 contingencies. For those C3 contingencies that don't currently meet the performance obligations after operator interventions, the subject facilities would be included PRC-023-2 R6 list of facilities. Note: CAISO does not sign on to the above comments.
Individual
Alice Ireland
Xcel Energy
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
B1) The NERC book of flowgates for the Eastern Interconnection includes a combination of permanent and temporary flowgates. This criteria should only use the permanent flowgates and the text should be modified as indicated to reflect that. Each circuit that is a monitored Element 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 Element in the Texas Interconnection or Québec Interconnection, that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator. B3) This appears to link to the NUC-001 standard. We would suggest the following modification: "Each circuit that forms a path (as agreed to by the plant owner and the Transmission Entity) to supply off-site power to nuclear plants as established in the NPIR for NUC-001." B5) We suggest removing this one as it is too open ended and open to interpretation as to which additional circuits should be considered. If there are additional criteria that are determined later that should be included, then we suggest they be added by either a regional standard or a SAR to modify the NERC standard.

Consideration of Comments on Relay Loadability Order 733 — Project 2010-13

The Relay Loadability Order 733 Drafting Team thanks all commenters who submitted comments on the proposed second version of the Relay Loadability Standard PRC-023-2 that includes the applicability test in Attachment B. These standards were posted for a 45-day public comment period from November 1, 2010 through December 16, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 38 sets of comments, including comments from more than 67 different people from approximately 73 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

In this report, the comments have been organized by question number so that it is easier to see where there is consensus. The comments can be viewed in their original format on the following page:

http://www.nerc.com/filez/standards/SAR_Project%202010-13_Order%20733%20Relay%20Modifiations.html

Based on stakeholder comments the drafting team incorporated a significant number of changes to the standard to address many of the issues raised by the commenters and to fulfill the FERC directives in Order 733. The changes to the standard primarily clarify the obligations assigned to the entities and do not substantively modify the requirements. Significant changes include:

Applicability:

- Modified to separately address the circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5 versus the circuits to which the Planning Coordinator must apply the criteria in Attachment B per Requirement R6.

Effective Dates and Retirement Dates:

- The effective dates were modified to address the timeframe in which Facility owners must comply with Requirements R1 through R5 when the Planning Coordinator identifies a circuit for which the Facility owner must comply with the standard.

- The implementation timeframe for the circuits identified in PRC-023-2 was extended to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1. For circuits already identified and subject to the requirements in PRC-023-1, the existing implementation dates will remain in effect.

- The retirement dates of the corresponding requirements in PRC-023-1 are addressed in the implementation plan and are based on the specific requirements.

Requirements:

- Requirement R1: Criterion 10 was modified to provide additional clarity to ensure that protection settings do not expose transformers to fault level and duration that exceed their mechanical withstand capability. The drafting team has clarified this requirement by making it a separate part of criterion 10 and by indicating this criterion applies to load responsive transformer fault protective relays, if used. A footnote was added in reference to IEEE C.57-109-1993, which establishes subject-matter-expert consensus guidance for transformer through-fault-current duration, and helps clarify the meaning of mechanical withstand capability as used in this standard.

- Requirement R5: Registered Entities that set transmission line relays according to Requirement R1 criterion 12 are required to provide a list of the circuits associated with those relays to the Regional Entity at least once each calendar year, with no more than 15 months between reports. The drafting team modified the requirement to allow that an updated list of the circuits associated with those relays be provided. The drafting team also added clarification within the requirement that the purpose is to allow the ERO to compile a list of all circuits that have protective relay settings that limit circuit capability.

- Requirement R6: Significant modification of this requirement was made to avoid redundancy with other sections of this standard and to improve the clarity of the requirement. References made to the Statement of Compliance Registry were replaced with the phrase “that are included on a critical facilities list defined by the Regional Entity.” The drafting team believes that to maintain consistency with the NERC Statement of Compliance Registry Criteria, should the Regional Entity develop a critical facilities list for application of the Compliance Registry Criteria, the Planning Coordinator would have to apply the criteria in Attachment B to determine for which of the circuits on the list the applicable entities must comply with the standard.

- Requirement R7: Requirement R7 was deleted to remove the double jeopardy concern between Requirements R1 through R5 and Requirement R7. The intent of R7 has been incorporated into the Effective Dates section, which has been modified to address the timeframe in which Facility owners must comply with Requirements R1 through R5 when the Planning Coordinator identifies a circuit for which the Facility owner must comply with the standard.

Measures:

- The Measures for each requirement were updated accordingly to reflect the changes in the requirement.

VRFs and VSLs:

- The VRFs and VSLs for each requirement were updated accordingly to reflect the changes in the requirement.

Attachment B:

- Significant modifications were made to Attachment B to help clarify the purpose and understanding of the requirements of this standard and the applicability of the criteria identified in Attachment B. The circuits to be evaluated and the criteria used to determine applicability to the PRC-023-2 standard were changed to clarify the requirements and to address the concerns raised by the stakeholders.

The drafting team strived to address and resolve all of the issues raised by the stakeholders. A number of comments were not incorporated because the drafting team believes they are not consistent with the reliability objectives of this standard. Other issues or suggested modifications were not implemented at this time, as it was felt that the next revision of the standard may be the best venue for such changes. Among these minority issues are the following:

- Expanding the purpose statement of the standard to include the need for relay settings to be shared and available
- Periodicity of data submittal and retention
- Gradations for VSLs in requirements other than R6, and following the NERC guidelines for these gradations
- Clarification and consistency among the statement of the requirements that may better reflect the intention or purpose of each
- Assorted suggestions for various proposed changes that were relative to approved content of PRC-023-1

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, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

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	Mike Garton	Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michael Gildea	Dominon Resources Services, Inc.	MRO	5, 6
2.	Louis Slade	Dominion Resources Services, Inc.	SERC	5, 6
3.	John Loftis	Dominion Virginia Power	SERC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	David K Thorne	Potomac Holdings Inc & Affiliates	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carl Kinsley		RFC	1
2.	Alvin Depew		RFC	1
3.	Bob Reuter	Pepco LSE	RFC	3
4.	Mike Mayer	DPL LSE	RFC	3
5.	Jim Petrella	ACE LSE	RFC	3

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

Additional Member	Additional Organization	Region	Segment Selection

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

1.	Al Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Michael Schiavone	National Grid	NPCC	1
4.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
5.	Dean Ellis	Dynegy Generation	NPCC	5
6.	Brian Evans-Mongeon	Utility Services	NPCC	8
7.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
8.	Randy MacDonald	New Brunswick System Operator	NPCC	2
9.	Michael R. Lombardi	Northeast Utilities	NPCC	1
10.	Kurtis Chong	Independent Electicity System Operator	NPCC	2
11.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
14.	Chantel Haswell	FPL Group, Inc.	NPCC	5
15.	David Kiguel	Hydro One Networks Inc.	NPCC	1
16.	Bruce Metruck	New York Power Authority	NPCC	6
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	Robert Pellegrini	The United Illuminating Company	NPCC	1
20.	Saurabh Saksena	National Grid	NPCC	1

				1	2	3	4	5	6	7	8	9	10
4.	Group	Steve Alexanderson	Pacific Northwest Small Public Power Utility Comment Group			X	X						

	Additional Member	Additional Organization	Region	Segment Selection
1.	Russell Noble	Cowlitz County PUD No. 1	WECC	3, 4, 5

				1	2	3	4	5	6	7	8	9	10
5.	Group	Bill Middaugh	Tri-State G & T System Protection	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Pearsall	TSGT	WECC	1, 3, 5, 6

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

2. Gary Preslan	TSGT	WECC	1, 3, 5, 6
3. LeRoy Martinez	TSGT	WECC	1, 3, 5, 6
4. Matthew Leyba	TSGT	WECC	1, 3, 5, 6

6.	Group	Jason Marshall	Midwest ISO Standards Collaborators		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Terry Harbour	Midamerican Energy	MRO	1
2. Jim Cyrulewski	JDRJC Associates, LLC	RFC	8
3. Barb Kedrowski	Wisconsin Electric	RFC	3, 4, 5

7.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
4.	Jason Marshall	Midwest ISO Inc.	MRO	2
5.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
6.	Ken Goldsmith	Alliant Energy	MRO	4
7.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
8.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
9.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
10.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
11.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
12.	Scott Nickels	Rochester Public Utilties	MRO	4
13.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
14.	Richard Burt	Minnkota Power Cooperative, Inc.	MRO	1, 3, 5, 6

8.	Group	Terry L. Blackwell	Santee Cooper	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.	Rene' Free	Santee Cooper	SERC	1
2.	Bridget Coffman	Santee Cooper	SERC	1
3.	Vicky Budreau	Santee Coope	SERC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection	
1.	Dean Bender	BPA, Transmission, SPC Technical Svcs	WECC	1
2.	Chuck Matthews	BPA, Transmission Planning		1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection	
1.	Sam Ciccone	FE	RFC	1, 3, 4, 5, 6
2.	Jim Detweiler	FE	RFC	1
3.	Jim Huber	FE	RFC	1
4.	Larry Wilson	FE	RFC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Ben Li	IRC Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Phillips	MISO	MRO	2
2.	Patrick Brown	PJM	RFC	2
3.	Steve Myers	ERCOT	ERCOT	2
4.	Greg Van Pelt	CAISO	WECC	2
5.	Matt Goldberg	ISO-NE	NPCC	2
6.	Mark Thompson	AESO	WECC	2
7.	Charles Yeung	SPP	SPP	2
8.	James Castle	NYISO	NPCC	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
12.	Individual	Joshua Wooten	Tennessee Valley Authority	X		X		X	X				
13.	Individual	Bruce Metruck	New York Power Authority					X					
14.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
15.	Individual	Mace Hunter	Lakeland Electric			X							
16.	Individual	Joe O'Brien for Tom Nappi	NIPSCO	X		X		X	X				
17.	Individual	Nicholas Klemm	Western Area Power Administration	X								X	
18.	Individual	Richard Burt	Minnkota Power Cooperative, Inc.	X									
19.	Individual	Kathleen Goodman	ISO New England Inc.		X								
20.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
21.	Individual	Tim Hinken	Kansas City Power & Light	X		X		X	X				
22.	Individual	Andrew Pusztai	American Transmission Company	X									
23.	Individual	David Burke	Orange and Rockland Utilities, Inc.	X		X							
24.	Individual	J. S. Stonecipher, PE	City of Jacksonville Beach, FL dba/Beaches Energy Services	X								X	
25.	Individual	Thad K. Ness	American Electric Power	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
26.	Individual	Steve Wadas	Nebraska Public Power District	X		X		X					
27.	Individual	Joe Knight	Great River Energy	X		X		X	X				
28.	Individual	Dan Rochester	Independent Electricity System Operator		X								
29.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
30.	Individual	Armin Klusman	CenterPoint Energy	X									
31.	Individual	Gregory Campoli	New York Independent System Operator		X								
32.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
33.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
34.	Individual	Kirit Shah	Ameren	X		X		X	X				
35.	Individual	Saurabh Saksena	National Grid	X		X							
36.	Individual	Jeff Billo	ERCOT ISO		X								
37.	Individual	Terry Harbour	MidAmerican Energy	X		X		X	X				
38.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				

1. *Requirement R1 defines the criteria 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. Criterion 10 of Requirement R1 was modified to ensure that protection settings do not expose transformers to fault level and duration that exceeds their mechanical withstand capability. Do you agree with the modification to criterion 10 in Requirement R1? If not, please explain and provide specific suggestions for improvement.*

Summary Consideration: In response to Question 1, stakeholders who responded to this question were fairly evenly divided – where about half agreed with Requirement R1 and about half disagreed with the proposed requirement. Aside from the typographical error in Requirement R1, criterion 9, criteria 10 and 11 received the majority of the comments. Criterion 10 has been modified by the drafting team in response to the respondents' comments to provide additional clarity to the requirement. A footnote has also been added in reference to IEEE C.57-109-1993, which establishes subject-matter-expert consensus guidance for transformer through-fault-current duration, and helps clarify the meaning of mechanical withstand capability as used in this standard. The drafting team also clarified that criterion 10 addresses fault protection relays and their response to load, and criterion 11 explicitly addresses thermal overload protection. The scope of PRC-023-2 was to address the directives provided by FERC in Order 733, and the drafting team deliberately limited the scope of changes it made to this standard to address those directives.

Organization	Yes or No	Question 1 Comment
Electric Market Policy	Yes	
Potomac Holdings Inc & Affiliates	Yes	Please note that a typographical error exists in Requirement R1 Criterion 9. The sentence should end with the phrase "flow from the load to the system under any system configuration". The words load and system have been inadvertently omitted in both this draft and the previous draft.
Response: Thank you for your comment. The text of the standard has been corrected.		
Northeast Power Coordinating Council	No	1) Clarification is needed on whether criterion 10 requires a transformer to have load responsive protection to protect from mechanical damage, either from internal faults, or through faults. If load responsive protection for the transformer element does not presently exist, i.e. only differential protection exists for the transformer element, will load responsive transformer protection have to be added to comply with this criterion? 2) The wording in criterion 10 should be changed to "Set transformer fault protection relays or transmission line relays on transmission lines terminated only with a transformer to ...." 3) Is this criteria requiring that a transformer with only differential protection and no other load responsive

Organization	Yes or No	Question 1 Comment
		remote protection be supplemented additional load responsive protection? 4) The loading on phase angle regulators, and series reactors should be considered and mentioned. 5) Also, there appears to be words missing in criterion 9 of R1: "the maximum current flow from the ? to the ? under any system configuration." From the NERC Webinar on 11/23/10 the intention was to address the possible locations where phase protection for the transformer could exist and not imply that this protection was needed at both locations.
Response: Thank you for your comments. 1) The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10, if it does exist. The standard has been modified to clarify this point. 2) The drafting team has considered this comment and similar comments and has modified the text of the standard as appropriate. 3) The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point. 4) The drafting team believes that the phase angle regulating transformers are already included in the standard in criteria 10 and 11, and that series reactors are already included as part of the element in which they are inserted. This comment will be considered further as we prepare future versions of the standard. 5) The text of the standard has been corrected.		
Pacific Northwest Small Public Power Utility Comment Group	No	1) The comment group finds R1.10 very confusing when attempting to understand it in the context of IEEE C57.109-1993. C57.109 identifies a solid curve as the thermal damage curve, while a dotted dog leg is the mechanical damage curve. Generally the dog leg is only considered for those class II and III transformers subjected to frequent through faults and all class IV transformers. Is the intent of the SDT to require this level of protection for all transformers regardless of through fault frequency and/or transformer class? If the SDT really meant to protect transformers from thermal or combination damage, please note that it is not possible to completely protect transformers from the thermal damage of low current long duration faults while still complying with the 150% of maximum rating. The thermal damage curve extends down to twice the base current. A footnote in C57.109 states that base current is established from the lowest nameplate kVA rating. A typical transformer with two stages of cooling will have a high nameplate rating of 1.67 times this base rating. The first bullet of R1.10 states affected entities must allow 1.5 times the maximum, so we are up to 2.5 times the base rating. Since we must allow this much without tripping, the relay must be set even higher. 1.2 times would be a secure margin, so the relay is set to pickup at 3 times the base rating. This setting would of course violate the first part of R1 criterion 10 because the transformer's fault capability would be exceeded for faults between 2 and 3 times the base rating. 2) We also note that criterion 11 is apparently an exception to criterion 10, but this is not altogether clear

Organization	Yes or No	Question 1 Comment
		since 10 is for fault protection while 11 is for overload protection. Please rewrite this (these) criterion (criteria) to clarify the SDT's intent(s).
Response: Thank you for your comments. 1) The drafting team has clarified this requirement by making it a separate part of criterion 10 and by indicating this criterion applies to load responsive transformer fault protective relays, if used. A footnote has been added to criterion 10 to clarify this requirement is based on the "dotted line" in IEEE C57.109-1993 – *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4. The drafting team intended this criterion to apply to mechanical withstand capability for through faults. Coordination for transformer thermal protection is covered in criterion 11. 2) Criterion 10 and criterion 11 are meant to address separate applications. Criterion 10 addresses fault protection relays and their response to load; criterion 11 explicitly addresses thermal overload protection.		
Tri-State G & T System Protection	No	There can be cases where the transformer withstand capability will be exceeded if 150% of the applicable maximum transformer rating is used for the pickup of overcurrent relays. The requirement cannot then be met if no transformer emergency rating is established. Modify to indicate that if the loading requirement violates the protection requirement, then the protection requirement should be used while allowing the maximum loading possible without violating the protection requirement.
Response: Thank you for your comments. The drafting team has clarified this requirement by making it a separate part of criterion 10 and by indicating this criterion applies to load responsive transformer fault protective relays, if used. A footnote has been added to criterion 10 to clarify this requirement is based on the "dotted line" in IEEE C57.109-1993 – *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4. The drafting team notes that 150 percent of a typical maximum transformer nameplate rating is on the order of 250 percent (150 percent x 1.67) of the base nameplate rating. The vertical portion of the mechanical withstand curve is defined by $1/(2xZ_t)$, which for a transformer with 12 percent impedance is approximately 400 percent of the nameplate base rating, allowing protection to be set above the loadability requirement in criterion 10 and below the transformer mechanical withstand curve. For cases where transformer overload protection is applied and the protection cannot be set above the loadability requirement in criterion 11 and below the thermal withstand curve, then supervision must be applied as noted in the second bullet of criterion 11.		
Midwest ISO Standards Collaborators	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
Santee Cooper	Yes	

Organization	Yes or No	Question 1 Comment
Bonneville Power Administration	No	BPA believes that FERC does not fully understand how transformers are rated and applied on the Bulk Electric System. Therefore, we believe the concern they expressed in their NOPR and Order 733 regarding the reliability of the Bulk Electric System being jeopardized by operating a transformer at 150% of its nameplate rating is unfounded. In response to FERC's concern, NERC has modified Criterion 10, which now has two conflicting requirements-ensuring that there is no operation for one level of load and ensuring that there is operation for another level of load. In some cases, these two load levels overlap and both requirements cannot be achieved simultaneously. The requirement in Criterion 10 that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability is ambiguous. It is not clear how the mechanical withstand capability is to be determined. IEEE Standard C57.109 provides recommended transformer through-fault duration limits, but these do not represent the actual mechanical withstand capability of transformers. IEEE Standard C57.12.00 specifies that transformers shall be designed and constructed to withstand the mechanical and thermal stresses produced by a fault limited only by the transformer impedance, or for category III and IV transformers, transformer impedance plus system impedance, for a duration of two seconds. However, the standard specifies that for currents between rated current and maximum short-circuit current the allowable time duration should be obtained by consulting the manufacturer. These standards do not clearly indicate what the mechanical withstand capability of transformers are. Certainly, for many existing transformers, there is no available manufacturer's data for this either, and it is unclear how to comply with Criterion 10. BPA feels this is too ambiguous and exposes entities to an unnecessary risk of possibly being sanctioned based on the judgment of an auditor. BPA believes that FERC's concern about transformer damage at the loading levels addressed by this standard is unfounded and contradictory to the purpose of this standard. The purpose of PRC-023 is to prevent automatic relay operations--which could cause cascading outages and quickly deteriorate the reliability of the BES--during severe system loading conditions. Under these loading conditions it is desirable that system operators have time to take corrective action to mitigate system problems before automatic relay operations accelerate the problem into a blackout. IEEE Standard C57.109 indicates that transformers can sustain 200% of rated load for at least thirty minutes. If relays are set to operate in this range, they are at risk of tripping a transformer under emergency loading situations, which exasperates the very problem that PRC-023 is attempting to eliminate. Most utilities have developed emergency ratings for their transformers. When a transformer load exceeds a predetermined level, the system operators are alarmed so that they can take appropriate action. During stressed system conditions, allowing a critical transformer to operate up to these emergency ratings could prevent a blackout. Conversely, requiring relays to be set in this range could result in the automatic loss of critical transformers, thereby accelerating the collapse of the bulk electric system. The ability of transformers to carry load without thermal damage or with acceptable levels of loss of life has been under study for many decades. There are many variables, such as ambient temperature, duty cycle, acceptable loss of life, etc., that determine the load and duration that a transformer is capable of. It has been addressed in transformer design and relay protection standards. Many utilities have made considerable efforts to determine the appropriate levels of emergency loading for their transformers. The mechanical

Organization	Yes or No	Question 1 Comment
		withstand capability of a transformer is not the relevant factor at the load levels addressed by PRC-023. BPA is concerned that we might be on the verge of superseding these many decades of research and experience with a poorly written, ambiguous, and inapplicable requirement because of the misunderstanding of the FERC commissioners. BPA suggests that NERC resist FERC's demands for setting relays to operate within the emergency operating capabilities of transformers. Additionally, BPA believes that there is no reason for FERC to be concerned with transformer overload protection. There is not a widespread problem with transformers being overloaded, and placing requirements on the industry for transformer protection results in an increased burden and expense to the industry with no resulting benefits. The subject of transformer loading has gained FERC's attention only as a result of its inclusion in PRC-023, and is not a problem for the BES-mostly because the industry has done the opposite of what FERC is now asking and not set transformer relays to operate in the emergency loading region. If transformer protection were an issue, it would be worthy of an individual standard, separate from PRC-023, because it is too complex to address in a short paragraph such as Criterion 10.Finally, BPA believes that Requirement 1 is unclear. It states that each TO, GO, and DP shall use any one of the 13 criteria for any specific circuit terminal to prevent its phase protective relays from limiting transmission loadability. Does this mean that the requirements of Criterion 10 only apply if Criterion 10 is used as the basis for justifying the relay settings of a terminal? If the relay settings for a transformer-terminated line are justified by one of the other criteria, say Criterion 1, is an entity allowed to ignore the requirements of Criterion 10 for the transformer overcurrent relays? Are transformer relays for transformers that aren't part of a transformer-terminated line subject to Criterion 10?BPA recommends that the words "such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability" be removed from Criterion 10. In addition, if all transformer overcurrent relays-not just those for transformer-terminated lines-are subject to the requirements of Criterion 10 (as suggested by Attachment A), they need to be addressed in a separate requirement because the 13 criteria of Requirement 1 are not necessarily mandatory.

Response: Thank you for your comments.

The drafting team has clarified this requirement by making it a separate part of criterion 10 and by indicating this criterion applies to load responsive transformer fault protective relays, if used. A footnote has been added to criterion 10 to clarify this requirement is based on the "dotted line" in IEEE C57.109-1993 – *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4. The drafting team notes that 150 percent of a typical maximum transformer nameplate rating is on the order of 250 percent (150 percent x 1.67) of the base nameplate rating. The vertical portion of the mechanical withstand curve is defined by 1/(2xZt), which for a transformer with 12 percent impedance is approximately 400 percent of the nameplate base rating, allowing protection to be set above the loadability requirement in criterion 10 and below the transformer mechanical withstand curve.

For cases where transformer overload protection is applied and the protection cannot be set above the loadability requirement in criterion 11 and below the thermal withstand curve, then supervision must be applied as noted in the second bullet of criterion 11.

Organization	Yes or No	Question 1 Comment
FirstEnergy	No	1) Criterion 10 does not take bidirectional load flow into consideration which could compromise the entity's ability to provide backup protection for the transmission system. We suggest the following wording for criterion 10: "Set transformer fault protection relays and transmission line 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 and so that the relays do not operate at or below the greater of:ï,§ 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment for load flow from the normal source side to the normal load side.ï,§ 115% of the highest operator established emergency transformer rating for load flow from the normal source side to the normal load side.ï,§ 115% of the maximum current flow from the normal load side to the normal source side under any system configuration." 2) We also ask that the team consider similar wording be added to Criterion 11 as suggested above for consistency with Criterion 10. 3) Criterion 9 seems to be missing some words in the phrase "flow from the to the under any system configuration". It appears this should say "from the load to the system under any system configuration."
Response: Thank you for your comments. 1) The issue of bidirectional flow is outside the scope of this project and will be considered as part of future enhancements to the standard. 2) The issue of bidirectional flow is outside the scope of this project and will be considered as part of future enhancements to the standard. 3) The text of the standard has been corrected.		
Tennessee Valley Authority	Yes	
New York Power Authority	No	1) Clarification is needed on whether criterion 10 requires a transformer to have load responsive protection to protect from mechanical damage, either from internal faults, or through faults. If load responsive protection for the transformer element does not presently exist (i.e., only differential protection exists for the transformer element) will load responsive transformer protection have to be added to comply with this criterion? 2) The wording in criterion 10 should be changed to "Set transformer fault protection relays or transmission line relays on transmission lines terminated only with a transformer to ...." 3) Is this criterion requiring that a transformer with only differential protection and no other load responsive remote protection be supplemented with additional load responsive protection?

Organization	Yes or No	Question 1 Comment
		4) The loading on phase angle regulators, and series reactors should be considered and mentioned. 5) Also, there appears to be words missing in criterion 9 of R1: “the maximum current flow from the ? to the ? under any system configuration.” From the NERC Webinar on 11/23/10 the intention was to address the possible locations where phase protection for the transformer could exist and not imply that this protection was needed at both locations.
Response: Thank you for your comments. 1) The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point. 2) The drafting team has considered this comment and similar comments and has modified the text of the standard. 3) The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point. 4) The drafting team believes that the phase angle regulating transformers are already included in the standard in criteria 10 and 11, and that series reactors are already included as part of the element in which they are inserted. This comment will be considered as we prepare future versions of the standard. 5) The text of the standard has been corrected.		
Manitoba Hydro	Yes	
Lakeland Electric	Yes	
NIPSCO	No	The mechanical withstand is not an appropriate value because every fault event will reduce the life of a transformer. Setting the limit at the maximum expected one-time event limit will prematurely destroy the transformers. Maybe a sliding scale would be better with each transformer owner to decided how much expected life to risk for faults.
Response: Thank you for your comments. IEEE C57.109-1993, *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, establishes subject-matter-expert consensus guidance for transformer through-fault-current duration. The mechanical withstand characteristic is discussed in IEEE C57.109-1993 relative to faults that will occur frequently. Criterion 10 is consistent with IEEE C57.109-1993.		
Western Area Power Administration	No	1) Established industry standards and practices have defined the mechanical damage portion of the transformer curve to apply for repetitive faults. Neither FERC nor NERC should have the right to contradict established technical practices. Entities should be able to coordination protection systems

Organization	Yes or No	Question 1 Comment
		taking into account protection and controls (e.g. the use of lockouts) which prevent repetitive exposure to mechanical damage thereby alleviating cumulative effects. 2) Also, it is not clear what "transmission line relays on transmission lines terminated only with a transformer..." applies to. Need clarification.
Response: Thank you for your comments. 1) IEEE C57.109-1993, *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, establishes subject-matter-expert consensus guidance for transformer through-fault-current duration. The mechanical withstand characteristic is discussed in IEEE C57.109-1993 relative to faults that will occur frequently. Criterion 10 is consistent with IEEE C57.109-1993. 2) The drafting team believes that this comment addresses approved content in PRC-023-1, and is therefore outside the scope of this project.		
Minnkota Power Cooperative, Inc.	Yes	
Duke Energy	Yes	
Kansas City Power & Light	Yes	
American Transmission Company	Yes	
Orange and Rockland Utilities, Inc.	No	1) Clarification is needed on whether criterion 10 requires a transformer to have load responsive protection to protect from mechanical damage. 2) The wording in criterion 10 should be changed to “set transformer fault protection relay or transmission line relay on transmission line terminated with only a transformer.” 3) Is this criterion requiring that a transformer with only differential protection and no other load responsive remote protection be mitigated with additional load responsive protection? 4) The loading on phase angle regulators, and series reactors should also be considered and mentioned.
Response: Thank you for your comments. 1) The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point.		

Organization	Yes or No	Question 1 Comment
2) The drafting team has considered this comment and similar comments and has modified the text of the standard. 3) The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point. 4) The drafting team believes that the phase angle regulating transformers are already included in the standard in criteria 10 and 11, and that series reactors are already included as part of the element in which they are inserted. This comment will be considered as we prepare future versions of the standard.		
City of Jacksonville Beach, FL dba/Beaches Energy Services	Yes	However, R1 and R2 have binary VSLs, where they should be percentages of all relays that need to meet the standard based on statistical sampling.
Response: Thank you for your comment. The VSLs defined are consistent with the VSLs already approved by FERC in PRC-023-1.		
American Electric Power	No	American Electric Power sees two issues with R1's Criterion 10. First, transformer "mechanical withstand capability" is undefined, vague, and subject to various interpretations. The terminology used in this criterion must be more tightly defined to prevent ambiguity or else referenced to some agreed-upon standard such as IEEE C57.109-1993. Second, American Electric Power agrees that it is appropriate for the 150% and 115% settings criteria to apply to line relays terminated only with a transformer. However, Criterion 10 seems to assume that transmission line relays on transmission lines terminated with a transformer are also typically intended to protect the transformer. This is not normally or necessarily true. If the line relays are not intended to protect the transformer and as long as the transformer relaying properly protects the transformer from mechanical damage, there is no reason for Criterion 10 to apply to the line relays. To address these two deficiencies in Criterion 10, American Electric Power sets forth the following two-part replacement language for Criterion 10:10.1 Set transformer fault protection relays such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability as defined by IEEE C57.109-1993 or its successor standard and so that the relays do not operate at or below the greater of: o 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment. o 115% of the highest operator established emergency transformer rating.10.2 Set transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of: o 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment. o 115% of the highest operator established emergency transformer rating. If the transformer fault protection relays on the line-terminated transformer do not expose the transformer to fault level and duration that exceeds its

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td></td><td></td><td>mechanical withstand capability, then the transmission line relays do not also need to provide the same protection against transformer mechanical damage.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
The drafting team agrees that mechanical withstand capability requires further clarification and has added a footnote that this requirement is based on the “dotted line” in IEEE C57.109-1993 – IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration, Clause 4.4, Figure 4.
The drafting team also agrees that while both the transmission line and transformer fault protection must meet the relay loadability requirement, it is sufficient for only the transformer fault protection to coordinate with the mechanical withstand capability. The drafting team has clarified this requirement by making it a separate part of criterion 10 and by indicating this criterion applies to load responsive transformer fault protective relays, if used.
The drafting team believes the modifications address the commenter’s concern, although through different modifications than those recommended by the commenter.</td></tr>
<tr><td>Nebraska Public Power District</td><td>Yes</td><td></td></tr>
<tr><td>Great River Energy</td><td>Yes</td><td></td></tr>
<tr><td>Independent Electricity System Operator</td><td>No</td><td>1) Clarification is needed on whether criterion 10 requires a transformer to have load responsive protection to protect from mechanical damage.
2) The wording in criterion 10 should be changed to “set transformer fault protection relay or transmission line relay on transmission line terminated with only a transformer.”
3) Is this criterion requiring that a transformer with only differential protection and no other load responsive remote protection be mitigated with additional load responsive protection?</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1) The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point.
2) The drafting team has considered this comment and similar comments and has modified the text of the standard.
3) The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point.</td></tr>
<tr><td>Northeast Utilities</td><td>No</td><td>Further clarification is needed for this criterion.
1) Is it the intention of this criterion that all applicable transformers must have load responsive protection to</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		prevent mechanical damage from a through fault? If load responsive protection for the transformer element does not presently exist, i.e. only differential protection exists for the transformer element, will load responsive transformer protection have to be added to comply with this criterion? 2) It is also suggested that R1 Criterion 10 wording be changed to "Set transformer fault protection relays or transmission line relays on transmission lines terminated only with a transformer to ...." since it appears from the NERC Webinar on 11/23/10 that the intention was address the possible locations where phase protection for the transformer could exist and not infer that this protection was needed at both locations.
Response: Thank you for your comments. 1) The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point. 2) The drafting team has considered this comment and similar comments and has modified the text of the standard.		
New York Independent System Operator	Yes	
Oncor Electric Delivery Company LLC	No	In paragraph 209 of Order No 733 it states: Since Requirement R1.10 applies to any topology, it must be robust enough to address the reliability issues of any topology. In light of the above statement criterion 10 of Requirement R1 should be modified to read as follows: Set transformer fault protection relays and transmission line relays used for transformer fault protection such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability and so that the relays do not operate at or below the greater of: By eliminating the special topology of "transmission lines terminated only with a transformer" from criterion 10 it eliminates any ambiguity that the criterion only applies to special transmission line cases and complies with the FERC assertion that the Requirement "applies to any topology." Oncor like other Transmission Owners provides autotransformer protection from possible thermal damage due to either prolonged through faults or load with its transformer overload protection relays. Protection of all autotransformers from fault level and duration that exceeds their mechanical withstand capability is provided by the redundant phase and ground relay settings of the local zones of protection coupled with local breaker failure protection. For prolonged faults that are outside the local zones of protection (not threatening damage to the transformer by exceeding the mechanical withstand capability of the transformer) or where loads exceed the thermal rating of the transformer the phase and ground transformer overload protection relays protect the transformer from thermal damage.

Organization	Yes or No	Question 1 Comment
		Based on the fact that at many locations a transformer is protected by local Protection Systems from prolonged “Close in” phase and ground through faults that might be within the fault level and duration that exceeds their mechanical withstand capability, criterion 11 of Requirement R1 should be modified as follows: For transformer overload protection relays that do not comply with the loadability or mechanical withstand capability components of Requirement R1, criterion 10 set the relays according to one of the following: If transformer protection from fault level and duration that exceeds a transformer’s mechanical withstand capability is provided by other Protection Systems, set the transformer overload protection settings to not expose the transformer to current level and duration that exceeds its thermal withstand capability and 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 or 115% of the highest operator established emergency transformer rating. 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 100Â° C for the top oil temperature or no less than 140Â° C for the winding hot spot temperature. Oncor believes that criterion 10 of Requirement R1 needs to be further modified as stated above to ensure that it applies to transmission lines of any topology and not just to transmission lines terminated only with a transformer. Oncor also feels that modifying criterion 10 of Requirement R1 by adding a requirement to ensure that protection settings do not expose transformers to fault level and duration requires that, for the reasons stated above, criterion 11 of Requirement R1 must be modified as noted above.

Response: Thank you for your comments.

Criterion 10 applies to (1) transformers fault protection relays and (2) transmission lines relays applied on transmission lines terminate only with a transformer. The drafting team notes the first clause of this criterion applies to all transformer configurations. The clause referring to transmission lines terminated only with a transformer delineates that criterion 10 does not apply to all transmission line relays.

The drafting team has clarified this requirement by making it a separate part of criterion 10 and by indicating this criterion applies to load responsive transformer fault protective relays, if used. A footnote has been added to criterion 10 to clarify this requirement is based on the “dotted line” in IEEE C57.109-1993 – *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4. The drafting team intended this criterion to apply to mechanical withstand capability for through faults. Coordination for transformer thermal protection is covered in criterion 11.

The drafting team believes that the comments regarding criterion 11 address approved content in PRC-023-1, and is therefore outside the scope of this project.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td>Consolidated Edison Co. of NY, Inc.</td><td>No</td><td>1) R1 - Clarification is needed on whether criterion 10 requires a transformer to have load responsive protection to protect from mechanical damage.
2) The wording in criterion 10 should be changed to “set transformer fault protection relay or transmission line relay on transmission line terminated with only a transformer.”
3) Is this criterion requiring that a transformer with only differential protection and no other load responsive remote protection be mitigated with additional load responsive protection?
4) The loading on phase angle regulators, and series reactors should also be considered and mentioned.
5) Also, there appears to be words missing in criterion 9 of R1: “the maximum current flow from the ? to the ? under any system configuration.”</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1) The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point.
2) The drafting team has considered this comment and similar comments and has modified the text of the standard.
3) The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point.
4) The drafting team believes that the phase angle regulating transformers are already included in the standard in criteria 10 and 11, and that series reactors are already included as part of the element in which they are inserted. This comment will be considered as we prepare future versions of the standard.
5) The text of the standard has been corrected.</td></tr>
<tr><td>Ameren</td><td>No</td><td>This additional statement is not necessary and already covered in R1 with the statement: ‘while maintaining reliable protection of the BES for all fault conditions.’</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
While this issue may have been implicitly addressed in Requirement R1, FERC Order 733 has directed that this issue be explicitly addressed in criterion 10.</td></tr>
<tr><td>National Grid</td><td>No</td><td>1) National Grid seeks clarification on whether criterion 10 requires transformer to have load responsive protection to protection from mechanical damage.
2) The wording in criterion 10 should be changed to “set transformer fault protection relay or transmission line relay on transmission line terminated with only a transformer.”</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		3) For example, is this criteria requiring that a transformer with only differential protection and no other load responsive remote protection be mitigated with additional load responsive protection?
Response: Thank you for your comments. 1) The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point. 2) The drafting team has considered this comment and similar comments and has modified the text of the standard. 3) The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point.		
ERCOT ISO	Yes	
MidAmerican Energy	Yes	
Xcel Energy	Yes	

2. *Requirement R2 requires the evaluation of out-of-step blocking schemes to verify that the out-of-step blocking elements allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. Note this new Requirement R2 does not add a new obligation on Transmission Owners, Generator Owners, and Distribution Providers; it only explicitly states in PRC-023-2 an obligation that presently is included in PRC-023 - Attachment A, section 2 of PRC-023-1. Do you agree with Requirement R2? If not, please explain and provide specific suggestions for improvement.*

Summary Consideration: In response to Question 2, most stakeholders who responded to this question indicated support for Requirement R2. The majority of the commenters were seeking clarification on the expected method for verifying that the out-of-step blocking elements allow tripping of phase protection relays for faults that occur during the loading conditions used to verify transmission line relay loadability. They were concerned about the potential for a costly and time consuming method for this verification. The drafting team has modified the requirement text to provide additional clarification, but it also points out that this requirement was included in Attachment A of PRC-023-1 and believes that it could be met by performing planning analyses of the relay settings.

Organization	Yes or No	Question 2 Comment
Electric Market Policy	Yes	
Potomac Holdings Inc & Affiliates	Yes	
Northeast Power Coordinating Council	Yes	
Pacific Northwest Small Public Power Utility Comment Group	Yes	
Tri-State G & T System Protection	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
Santee Cooper	No	We appreciate the drafting team addressing this issue, and, in general, agree with our understanding of the intention of this requirement. However, the wording of the section should be a little clearer. Through asking questions about the intention of these statements, it is our understanding that, as long as the composite scheme (made up of all the relay elements protecting the transmission line) will still operate for a fault in a time that is compliant with the TPL standards, that this requirement is met. This may mean that a particular

Organization	Yes or No	Question 2 Comment
		relay element may still be blocked, but there are other relay elements, possibly with a different time delay, that would still operate in an appropriate amount of time. As long as the total scheme protecting the element in question still meets all of the TPL and stability requirements for isolating the fault from the system, the operation of the scheme should be satisfactory. If this is still the intention, then it should be clarified in this requirement.
Response: Thank you for your comment. The drafting team has considered this comment and similar comments and has modified the text of the standard.		
Bonneville Power Administration	Yes	
FirstEnergy	Yes	
Tennessee Valley Authority	Yes	
New York Power Authority	Yes	
Manitoba Hydro	Yes	
Lakeland Electric	Yes	
NIPSCO	No	We believe this is already included
Response: Thank you for your comment. While this issue may have been addressed in Attachment A, FERC Order 733 has directed that this issue be explicitly addressed in a separate requirement.		
Western Area Power Administration	Yes	
Minnkota Power Cooperative, Inc.	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 2 Comment
Kansas City Power & Light	Yes	
American Transmission Company	Yes	
Orange and Rockland Utilities, Inc.	No	What is the expectation for verifying that the out-of-step blocking elements allow tripping of phase protection relays for faults that occur during the loading conditions used to verify transmission line relay loadability? It would be costly and time consuming to verify this. To comply with this requirement, utilities may have to remove OOS protections all together. This should be able to be tested during routine trip testing. Between the trip testing procedures, and relay calibrations this requirement should be satisfied, and easily documented.
Response: Thank you for your comment. The drafting team believes that this requirement will be met by a planning analysis of the settings. This is not a new requirement. PRC-023-1 requires, within Attachment A, that this analysis be done.		
City of Jacksonville Beach, FL dba/Beaches Energy Services	Yes	R1 and R2 have binary VSLs, where they should be percentages of all relays that need to meet the standard based on statistical sampling. (See previous comment for R1.)
Response: Thank you for your comment. The VSLs defined are consistent with the VSLs already approved by FERC in PRC-023-1.		
American Electric Power	Yes	
Nebraska Public Power District	Yes	
Great River Energy	Yes	
Independent Electricity System Operator	Yes	
Northeast Utilities	No	What is the expectation for verification that the out-of-step blocking elements allow tripping of phase protection relays for faults that occur during the loading conditions used to verify transmission line relay loadability? It would be very costly and time consuming to verify proper operation of these blocking schemes

Organization	Yes or No	Question 2 Comment
		for all of the various possible fault and loading combination scenarios for each application of this scheme.
Response: Thank you for your comment. The drafting team believes that this requirement will be met by a planning analysis of the settings. This is not a new requirement. PRC-023-1, within Attachment A, requires that this analysis be done.		
New York Independent System Operator		No comment from the PC & RC perspective, the TOs are responsible for designing phase protection schemes appropriate to their systems
Response: Thank you for your comment.		
Oncor Electric Delivery Company LLC	Yes	
Consolidated Edison Co. of NY, Inc.	No	R2 - What is the expectation for verifying that the out-of-step (OOS) blocking elements allow tripping of phase protection relays for faults that occur during the loading conditions used to verify transmission line relay loadability? It would be costly and time consuming to verify this. To comply with this requirement, utilities may have to remove OOS protections all together.
Response: Thank you for your comment. The drafting team believes that this requirement will be met by a planning analysis of the settings. This is not a new requirement. PRC-023-1, within Attachment A, requires that this analysis be done.		
Ameren	Yes	
National Grid	No	National Grid seeks clarification on what is the expectation for verifying that the out-of-step blocking elements allow tripping of phase protection relays for faults that occur during the loading conditions used to verify transmission line relay loadability? It would be costly and time consuming to verify this. To comply with this requirement, utilities may have to remove OOS protections all together.
Response: Thank you for your comment. The drafting team believes that this requirement will be met by a planning analysis of the settings. This is not a new requirement. PRC-023-1, within Attachment A, requires that this analysis be done.		

Organization	Yes or No	Question 2 Comment
ERCOT ISO	Yes	
MidAmerican Energy	Yes	
Xcel Energy	Yes	

3. *Requirement R4 requires the Registered Entities that choose to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability to provide the Planning Coordinator, Transmission Operator, and Reliability Coordinator with a list of facilities associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. Do you agree with Requirement R4? If not, please explain and provide specific suggestions for improvement.*

Summary Consideration: In response to Question 3, stakeholders who responded to this question were fairly evenly divided with about half indicating support for Requirement R4 and about half expressing some disagreement with the proposed requirement.

A significant number of commenters indicated that they believe PRC-023-2 Requirements R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology, and communicate those ratings and methodology to the Planning Coordinator, Reliability Coordinator and Transmission Operator. The drafting team states that FAC-008 and FAC-009 do not really address the Requirements stated in R3 and R4. The drafting team clarified that FAC-009 requires the communication of the Facility Rating, whereas PRC-023-2 requires notification when the relay loadability is based on a 15-minute rating.

Many of the commenters stated that they should only be required to provide the list of facilities with transmission line relays that use Requirement R1, criterion 2 to the Transmission Operators. The drafting team responded that since the Reliability Coordinators and Planning Coordinators both use the ratings data as part of their functional responsibilities that data must also be made available to them.

Many of the commenters were concerned about the proposed effective date for Requirements R4 & R5. The drafting team responded that since Requirements R4 & R5 only impose a reporting requirement, the shorter period of six months after regulatory approvals or Board of Trustees adoption is appropriate.

A significant number of the commenters indicated that they don't understand why a full list of facilities with transmission line relays that use Requirement R1 criterion 2 must be provided each year. These facilities will not change very often, and a new list should only be required when a change is made to the existing list. The drafting team considered these comments and revised Requirements R4 & R5 to require an updated list, and the associated measures have also been revised to indicate that the updated list may either be a full list or a list of incremental changes to the previous list

Organization	Yes or No	Question 3 Comment
Electric Market Policy	Yes	

Organization	Yes or No	Question 3 Comment
Potomac Holdings Inc & Affiliates	Yes	In the SDT's response "Consideration of Comments on Revisions to Relay Loadability for Order 733 SAR and an initial set of proposed requirements - Project 2010-13" dated November 1, 2010, the SDT proposed to establish the effective date for requirements R4 & R5 as "the first day of the first calendar quarter following 24 months after regulatory approvals." However in the latest draft of the standard the 24 month requirement was replaced with 6 months. Which is correct?
Response: Thank you for your comment. The effective date of the standard is the first day of the first calendar quarter following six months after regulatory approvals. Since this is only a reporting requirement, the drafting team believes that six months is appropriate.		
Northeast Power Coordinating Council	Yes	
Pacific Northwest Small Public Power Utility Comment Group	Yes	
Tri-State G & T System Protection	No	1) We believe that the list of facilities with transmission line relays that use Requirement R1 criterion 2 needs to be given only to the Transmission Operators as directed by Paragraph 186 of FERC Order no. 733, and not also to the Planning Coordinators and Reliability Coordinators. 2) We also believe that an initial submittal is sufficient until any responsible entity begins or stops using that criterion on any element. Periodic duplicate submittals are unnecessary and unique submittals would more easily identify the loadability issues that the operators need to consider. The FERC Order did not require annual submittals.
Response: Thank you for your comments. 1) Since the Reliability Coordinators and Planning Coordinators both use ratings data as part of their functional responsibilities, the drafting team believes that the data must be made available to them. 2) The requirement has been revised to require an updated list and the accompanying measure has been modified to indicate that the updated list may either be a full list or a list of incremental changes to the previous list.		
Midwest ISO Standards Collaborators	No	We do not believe this requirement is needed. Limiting a relay setting to 115% of the associated transmission line's highest seasonal 15 minute rating does not equate to a line that will trip before the operator has time to intervene. It does not mean the line will trip in 15 minutes. In fact, the operator should be taking action well in advance of reaching a 15 minute limit and the operator is likely only using the 15 minute rating in extreme

Organization	Yes or No	Question 3 Comment
		circumstances. Furthermore, PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings including those limited by relays. As a result, neither PRC-023-2 R3 nor R4 is even needed. We assume the drafting team must be aware of these FAC standard requirements because they did not even require reporting to the Reliability Coordinator, Planning Coordinator and Transmission Operator of those circuits that are actually limited by the relay per criterion 12. We agree that FAC-008-1 and FAC-009-1 collectively establish the necessary requirements to compel the Transmission Owner and Generator Owner to communicate these relay limited circuits and that no additional requirements are necessary.
Response: Thank you for your comments. Providing this information to the specified entities addresses the potential for confusion as to the amount of time available to take corrective action. FAC-008 and FAC-009 do not address this issue. FAC-009 requires transmitting the Facility Rating, whereas PRC-023-2 requires notification when the relay loadability is based on a 15-minute rating.		
MRO's NERC Standards Review Subcommittee	No	We do not believe this requirement is needed. Limiting a relay setting to 115% of the associated transmission line's highest seasonal 15 minute rating does not equate to a line that will trip before the operator has time to intervene. It does not mean the line will trip in 15 minutes. In fact, the operator should be taking action well in advance of reaching a 15 minute limit and the operator is likely only using the 15 minute rating in extreme circumstances. Furthermore, PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings including those limited by relays. As a result, neither PRC-023-2 R3 nor R4 is even needed. We assume the drafting team must be aware of these FAC standard requirements because they did not even

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>require reporting to the Reliability Coordinator, Planning Coordinator and Transmission Operator of those circuits that are actually limited by the relay per criterion 12.

We agree that FAC-008-1 and FAC-009-1 collectively establish the necessary requirements to compel the Transmission Owner and Generator Owner to communicate these relay limited circuits and that no additional requirements are necessary.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.

Providing this information to the specified entities addresses the potential for confusion as to the amount of time available to take corrective action.

FAC-008 and FAC-009 do not address this issue. FAC-009 requires transmitting the Facility Rating, whereas PRC-023-2 requires notification when the relay loadability is based on a 15-minute rating.</td></tr>
<tr><td>Santee Cooper</td><td>Yes</td><td></td></tr>
<tr><td>Bonneville Power Administration</td><td>No</td><td>BPA does not understand why a list of such facilities must be provided each year. These facilities will not change very often, and a new list should only be required when changes are made to the old list. Please explain why you feel it is necessary.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

The requirement has been revised to require an updated list and the accompanying measure has been modified to indicate that the updated list may either be a full list or a list of incremental changes to the previous list.</td></tr>
<tr><td>FirstEnergy</td><td>Yes</td><td></td></tr>
<tr><td>IRC Standards Review Committee</td><td>No</td><td>We do not believe this requirement is needed. Limiting a relay setting to 115% of the associated transmission line’s highest seasonal 15 minute rating does not equate to a line that will trip before the operator has time to intervene. It does not mean the line will trip in 15 minutes. In fact, the operator should be taking action well in advance of reaching a 15 minute limit and the operator is likely only using the 15 minute rating in extreme circumstances.

Furthermore, PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
		including those limited by relays. As a result, neither PRC-023-2 R3 nor R4 is even needed. We assume the drafting team must be aware of these FAC standard requirements because they did not even require reporting to the Reliability Coordinator, Planning Coordinator and Transmission Operator of those circuits that are actually limited by the relay per criterion 12. We agree that FAC-008-1 and FAC-009-1 collectively establish the necessary requirements to compel the Transmission Owner and Generator Owner to communicate these relay limited circuits and that no additional requirements are necessary. Note: CAISO does not sign on to the above comments.
Response: Thank you for your comments. Providing this information to the specified entities addresses the potential for confusion as to the amount of time available to take corrective action. FAC-008 and FAC-009 do not address this issue. FAC-009 requires transmitting the Facility Rating, whereas PRC-023-2 requires notification when the relay loadability is based on a 15-minute rating.		
Tennessee Valley Authority	Yes	
New York Power Authority	Yes	
Manitoba Hydro	Yes	
Lakeland Electric	Yes	
NIPSCO	No	We're not sure what the value is in this requirement?
Response: Thank you for your comment. Providing this information to the specified entities addresses the potential for confusion as to the amount of time available to take corrective action.		
Western Area Power Administration	Yes	
Minnkota Power Cooperative, Inc.	Yes	

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td>Duke Energy</td><td>Yes</td><td></td></tr>
<tr><td>Kansas City Power & Light</td><td>No</td><td>We do not believe this requirement is needed. Limiting a relay setting to 115% of the associated transmission line's highest seasonal 15 minute rating does not equate to a line that will trip before the operator has time to intervene. It does not mean the line will trip in 15 minutes. In fact, the operator should be taking action well in advance of reaching a 15 minute limit and the operator is likely only using the 15 minute rating in extreme circumstances.

Furthermore, PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings including those limited by relays. As a result, neither PRC-023-2 R3 nor R4 is even needed.

We assume the drafting team must be aware of these FAC standard requirements because they did not even require reporting to the Reliability Coordinator, Planning Coordinator and Transmission Operator of those circuits that are actually limited by the relay per criterion 12.

We agree that FAC-008-1 and FAC-009-1 collectively establish the necessary requirements to compel the Transmission Owner and Generator Owner to communicate these relay limited circuits and that no additional requirements are necessary.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.

Providing this information to the specified entities addresses the potential for confusion as to the amount of time available to take corrective action.

FAC-008 and FAC-009 do not address this issue. FAC-009 requires transmitting the Facility Rating, whereas PRC-023-2 requires notification when the relay loadability is based on a 15-minute rating.</td></tr>
<tr><td>American Transmission Company</td><td>Yes</td><td></td></tr>
<tr><td>Orange and Rockland Utilities, Inc.</td><td>Yes</td><td></td></tr>
<tr><td>City of Jacksonville Beach, FL</td><td>No</td><td>No, that is way too frequent. It should be a much longer time criteria, say 5 years, with a requirement that if</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
dba/Beaches Energy Services		there is a CHANGE, the information is sent to the PC, TO and RC.
Response: Thank you for your comment. The drafting team believes that updates need to be provided annually; the requirement has been revised to require an updated list and the accompanying measure has been modified to indicate that the updated list may either be a full list or a list of incremental changes to the previous list.		
American Electric Power	Yes	
Nebraska Public Power District	No	NERC does not need a separate requirement for TOs, GOs, and DPs to specifically report R1, criterion 2. If they meet the requirement the line will not trip. If they meet the requirement and the line is overloaded the operator will receive an alarm and will take action within 15 minutes.
Response: Thank you for your comment. Providing this information to the specified entities addresses the potential for confusion as to the amount of time available to take corrective action.		
Great River Energy	No	We do not believe this requirement is needed. Limiting a relay setting to 115% of the associated transmission line's highest seasonal 15 minute rating does not equate to a line that will trip before the operator has time to intervene. It does not mean the line will trip in 15 minutes. In fact, the operator should be taking action well in advance of reaching a 15 minute limit and the operator is likely only using the 15 minute rating in extreme circumstances. Furthermore, PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings including those limited by relays. As a result, neither PRC-023-2 R3 nor R4 is even needed. We assume the drafting team must be aware of these FAC standard requirements because they did not even require reporting to the Reliability Coordinator, Planning Coordinator and Transmission Operator of those circuits that are actually limited by the relay per criterion 12. We agree that FAC-008-1 and FAC-009-1 collectively establish the necessary requirements to compel the Transmission Owner and Generator Owner to communicate these relay limited circuits and that no additional requirements are necessary.
Response: Thank you for your comment. Providing this information to the specified entities addresses the potential for confusion as to the amount of time available to take corrective action.		

Organization	Yes or No	Question 3 Comment
FAC-008 and FAC-009 do not address this issue. FAC-009 requires transmitting the Facility Rating, whereas PRC-023-2 requires notification when the relay loadability is based on a 15-minute rating.		
Independent Electricity System Operator	No	As indicated in our previous comments, the FERC Directive asks for provision of this information to the TOP only. We question the need to go beyond what's being asked for in the Directive to require the responsible entities to provide this information to other entities (PC and RC). If a reliability need is not identified, we suggest that these two entities be removed from the requirement.
Response: Thank you for your comment. Since the Reliability Coordinators and Planning Coordinators both use ratings data as part of their functional responsibilities, the drafting team believes that the data must be made available to them.		
Northeast Utilities	Yes	Suggest clarification for Section 4.2.6 be added. That is, our review of the draft indicates that, as its title implies, this Standard primarily focuses on transmission relaying for lines and transformers. Nowhere does it mention generation relaying, per se, and the transformer relaying appears to be focused on "transmission" transformers and other transformers that have bi-directional flow capability. There is one sticking point, however. Section 4.2.6 seems to muddy the otherwise clear "transmission" directive in that it extends the applicability to: "4.2.6 Transformers with low voltage terminals connected below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry and the Planning Coordinator has determined are required to comply with this standard". While we believe that this was intended to pertain to transmission or load-serving transformers, due to ambiguity in the Standard this could be taken to mean transformers in facilities deemed "material to the reliability of the Bulk Power System." It could thus be applied (incorrectly, in our opinion) to generation facilities. We would also question why there would be a concern for the low voltage side of a GSU. Please clarify Section 4.2.6, as appropriate.
Response: Thank you for your comment. Transformers with low voltage terminals connected below 100 kV will be subject to the standard as determined by the application of the criteria in Attachment B, and any relevant responsive relays will need to comply with this standard. Generator relay loadability issues will be addressed in Phase 2 of Project 2010-13.		
CenterPoint Energy	No	CenterPoint Energy disagrees with providing a list to Planning Coordinators, Transmission Operators, and Reliability Coordinators, as we cannot see any need and do not expect these entities would utilize this information in any manner.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comment. Providing this information to the specified entities addresses the potential for confusion as to the amount of time available to take corrective action.		
New York Independent System Operator	No	PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1, and therefore unnecessary. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings including those limited by relays.
Response: Thank you for your comment. Providing this information to the specified entities addresses the potential for confusion as to the amount of time available to take corrective action. FAC-008 and FAC-009 do not address this issue. FAC-009 requires transmitting the Facility Rating, whereas PRC-023-2 requires notification when the relay loadability is based on a 15-minute rating.		
Oncor Electric Delivery Company LLC	No	Oncor feels that the Requirement R4 is too cumbersome for the Registered Entities who have to, every 12 to 15 months, provide to the Planning Coordinator, Transmission Operator and Reliability Coordinator massive amounts of information that rarely changes. Also by allowing up to 15 months between reports to the Planning Coordinator, Transmission Operator and Reliability Coordinator of relay setting changes made by Registered Entities these Operators and Coordinators are deprived of knowing changes to loading limitations for up to 15 months. To overcome the problems with Requirement R4 of the present version PRC-023-2 Oncor has two specific suggestions for improvement. First, Requirement R4 should be changed to have a onetime requirement for 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 to provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with a list of facilities associated with those transmission line relays. Second, Requirement R4 should be changed to require 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 to provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with any changes (additions, deletions or modifications) to the one time list of facilities associated with those transmission line relays within 30 days changes are made to list. By using the proposed changes to R4 listed above, the only information that needs be transferred between the Registered Entities and the Operators and Coordinators following the initial exchange of information are changes made to the initial information. By requiring the Registered Entities to notify the Operators and Coordinators shortly after changes are made the up to 15 month delay getting modifications to

Organization	Yes or No	Question 3 Comment
		them is eliminated.
Response: Thank you for your comment. The requirement has been revised to require an updated list and the accompanying measure has been modified to indicate that the updated list may either be a full list or a list of incremental changes to the previous list.		
Consolidated Edison Co. of NY, Inc.	Yes	
Ameren	No	This requirement is redundant with Standards FAC-008-1 and FAC-009-1. The existing standards already cover ratings methodologies and reporting of facility ratings to the appropriate entities. In addition, these two standards already require consideration of relaying equipment as one component in developing ratings methodologies and in reporting of those ratings.
Response: Thank you for your comment. Providing this information to the specified entities addresses the potential for confusion as to the amount of time available to take corrective action. FAC-008 and FAC-009 do not address this issue. FAC-009 requires transmitting the Facility Rating, whereas PRC-023-2 requires notification when the relay loadability is based on a 15-minute rating.		
National Grid	Yes	
ERCOT ISO	No	It is not clear what the Planning Coordinator and Reliability Coordinator is supposed to do with this information.
Response: Thank you for your comment. Since the Reliability Coordinators and Planning Coordinators both use ratings data as part of their functional responsibilities, the drafting team believes that the data must be made available to them.		
MidAmerican Energy	No	I don't believe this requirement is needed. Limiting a relay setting to 115% of the associated transmission line's highest seasonal 15 minute rating does not equate to a line that will trip before the operator has time to intervene. It does not mean the line will trip in 15 minutes. In fact, the operator should be taking action well in advance of reaching a 15 minute limit and the operator is likely only using the 15 minute rating in extreme circumstances. Furthermore, PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish

Organization	Yes or No	Question 3 Comment
		a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings including those limited by relays. As a result, neither PRC-023-2 R3 nor R4 is even needed. We assume the drafting team must be aware of these FAC standard requirements because they did not even require reporting to the Reliability Coordinator, Planning Coordinator and Transmission Operator of those circuits that are actually limited by the relay per criterion 12. We agree that FAC-008-1 and FAC-009-1 collectively establish the necessary requirements to compel the Transmission Owner and Generator Owner to communicate these relay limited circuits and that no additional requirements are necessary.
Response: Thank you for your comment. Providing this information to the specified entities addresses the potential for confusion as to the amount of time available to take corrective action. FAC-008 and FAC-009 do not address this issue. FAC-009 requires transmitting the Facility Rating, whereas PRC-023-2 requires notification when the relay loadability is based on a 15-minute rating.		
Xcel Energy	Yes	

4. *Requirement R5 requires the Registered Entities that set transmission line relays according to Requirement R1 criterion 12 to provide a list of the facilities associated with those relays to the Regional Entity at least once each calendar year, with no more than 15 months between reports. Do you agree with Requirement R5? If not, please explain and provide specific suggestions for improvement.*

Summary Consideration: In response to Question 4, stakeholders who responded to the question were fairly evenly divided with about half indicating support for Requirement R5 and about half indicating disagreement with some aspect of the proposed requirement.

The overwhelming concern submitted by the commenters was that while they didn't necessarily have an issue with the equipment owner communicating the relay limited circuits to the Regional Entities, they didn't believe this information is needed for reliability and, therefore, should not be included in the reliability standard. The drafting team pointed out in its response that FERC Order 733 has directed that this requirement be explicitly addressed within the requirements of PRC-023-2.

The commenters were also concerned with the frequency requirements for providing this data to the Regional Entities. The drafting team considered these concerns and revised the standard to require an updated list, and the associated measure was modified to indicate that the updated list may either be a full list or a list of incremental changes to the previous list. The drafting team believes that an annual update of the list is sufficient to satisfy the reliability goals of this requirement.

The drafting team also stated that including this requirement in the PRC-023 standard or collecting the data via a NERC Section 1600 Data Request are equally effective ways to address the directive. The drafting team has elected to address the directive within the standard. The drafting team allows that if this requirement is moved to Section 1600 of the NERC Rules of Procedure, it could be removed from the PRC-023 standard as part of the next subsequent revision.

The commenters also indicated that FERC Order 733 requires that the ERO document and have available upon request the list of facilities that use this criterion. The proposed standard is not applicable to the Regional Entity so there is no method to require the RE to provide the data to the ERO. The drafting team pointed out that each Regional Entity (RE), via the delegation agreements, is a part of the ERO; thus, by submitting the information to the RE, the ERO will have the information available to respond to requests from users, owners, and operators of the BES.

Organization	Yes or No	Question 4 Comment
Electric Market Policy	Yes	
Potomac Holdings Inc & Affiliates	Yes	In the SDT's response "Consideration of Comments on Revisions to Relay Loadability for Order 733 SAR and an initial set of proposed requirements - Project 2010-13" dated November 1, 2010, the SDT proposed to establish the effective date for requirements R4 & R5 as "the first day of the first calendar quarter following

Organization	Yes or No	Question 4 Comment
		24 months after regulatory approvals." However in the latest draft of the standard the 24 month requirement was replaced with 6 months. Which is correct?
Response: Thank you for your comment. The effective date of the standard is the first day of the first calendar quarter following six months after regulatory approvals. Since this is only a reporting requirement, the drafting team believes that six months is appropriate.		
Northeast Power Coordinating Council	Yes	
Pacific Northwest Small Public Power Utility Comment Group	No	The FERC Order 733 page 224 states that this information is to be made available to the entities "by request." Unless a request happens to coincide with the annual submittal, this order is not being addressed. There is also no requirement that the Regional Entity make the lists available to the other entities as ordered. We don't believe the intent of the order was achieved in R5.
Response: Thank you for your comment. The requirement has been revised to require an updated list and the accompanying measure has been modified to indicate that the updated list may either be a full list or a list of incremental changes to the previous list. The drafting team believes that an annual update of the list is sufficient to satisfy the reliability goals of this requirement. The Regional Entity (RE), via the delegation agreements, is a part of the ERO; thus, by submitting the information to the RE, the ERO will have the information available to respond to requests from users, owners, and operators of the BES.		
Tri-State G & T System Protection	No	Paragraph 224 of FERC Order no. 733 requires that the ERO document and have available upon request the list of facilities that use this criterion. The proposed standard is not applicable to the Regional Entity so there is no method to require the RE to provide the data to the ERO. That seems to indicate that the data should be provided to the ERO rather than the Regional Entity. We also believe that an initial submittal is sufficient until any responsible entity begins or stops using that criterion on any element. Periodic duplicate submittals are unnecessary and unique submittals would more easily identify the loadability issues that the operators need to consider. The FERC Order did not require annual submittals.
Response: Thank you for your comment. The requirement has been revised to require an updated list and the accompanying measure has been modified to indicate that the updated list may either be a full list or a list of incremental changes to the previous list. The drafting team believes that an annual update of the list is sufficient to satisfy the reliability goals of this requirement. The Regional Entity (RE), via the		

Organization	Yes or No	Question 4 Comment
delegation agreements, is a part of the ERO; thus, by submitting the information to the RE, the ERO will have the information available to respond to requests from users, owners, and operators of the BES.		
Midwest ISO Standards Collaborators	No	While we don't necessarily have an issue with the equipment owner communicating these relay limited circuits to the Regional Entities, we don't believe this is needed for reliability and therefore it should not be included in the reliability standard. Given that it is unclear what the information will even be used for, if it will be needed long-term, and that it is likely will not change much, if at all, from year to year, we believe a data request through NERC's Rules of Procedure section 1600 would be more appropriate. In that way, we don't have to modify the standard later when NERC and the Regions determine they don't need the data annually.
Response: Thank you for your comment. The drafting team believes that including this requirement in the standard or collecting the data via Section 1600 are equally effective ways to address the directive. The drafting team has elected to address the directive within the standard.		
MRO's NERC Standards Review Subcommittee	No	While we don't necessarily have an issue with the equipment owner communicating these relay limited circuits to the Regional Entities, we don't believe this is needed for reliability and therefore it should not be included in the reliability standard. Given that it is unclear what the information will even be used for, if it will be needed long-term, and that it is likely will not change much, if at all, from year to year, we believe a data request through NERC's Rules of Procedure section 1600 would be more appropriate. In that way, we don't have to modify the standard later when NERC and the Regions determine they don't need the data annually.
Response: Thank you for your comment. The drafting team believes that including this requirement in the standard or collecting the data via Section 1600 are equally effective ways to address the directive. The drafting team has elected to address the directive within the standard.		
Santee Cooper	Yes	
Bonneville Power Administration	No	Since a Registered Entity is already required to obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator and to use the calculated circuit capability as the Facility Rating of the circuit as required by R3, BPA would like additional information regarding the purpose of providing the Regional Entity a list each year. What would they do with the list?
Response: Thank you for your comment. The requirement has been revised to require an updated list and the accompanying measure has been modified to indicate that the updated list may either be a		

Organization	Yes or No	Question 4 Comment
full list or a list of incremental changes to the previous list. The drafting team believes that an annual update of the list is sufficient to satisfy the reliability goals of this requirement. The Regional Entity (RE), via the delegation agreements, is a part of the ERO; thus, by submitting the information to the RE, the ERO will have the information available to respond to requests from users, owners, and operators of the BES.		
FirstEnergy	No	FE recognizes that the standard drafting team introduced Requirement R5 in response to a FERC directive requiring NERC to document and make available upon request a list of protective relays set pursuant to Requirement R1, Criterion 12. We commend FERC in their Order 733 decision to retain Criterion 12 over accepting the preceding NOPR recommendation to remove it and support FERC's desire in making information readily available on entities application of Criterion 12 for its own use and other interested parties. We are not opposed to providing our Regional Entity the information desired but believe this presents an administrative task that can be accomplished outside of a mandatory and enforceable reliability requirement. Since the reported data is for informational purposes and not a reliability need, we encourage the drafting team propose to NERC staff an equally efficient and effective alternative of having the Regional Entity periodically obtain the data through NERC's Rules of Procedure, Section 1600 titled "Request for Data or Information". Note: First Energy provided the following proposed changes to its comment: "We are not opposed to providing our Regional Entity the information desired, however, FE believes it is more efficient if the Registered Entity were to respond to a request for information from their Regional Entity. This change would benefit both parties. The Regional Entity benefits by controlling when they receive the information, rather than having to process data at different times throughout the year. The Registered Entity benefits by limiting compliance exposure to an annual administrative task that could be easily overlooked. Therefore, we propose that requirement R5 be revised as follows: R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide a list of the facilities associated with those relays to its Regional Entity upon request, within 30 days of the request. [Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]
Response: Thank you for your comment. The requirement has been revised to require an updated list and the accompanying measure has been modified to indicate that the updated list may either be a		

Organization	Yes or No	Question 4 Comment
full list or a list of incremental changes to the previous list. The drafting team believes that an annual update of the list is sufficient to satisfy the reliability goals of this requirement. The Regional Entity (RE), via the delegation agreements, is a part of the ERO; thus, by submitting the information to the RE, the ERO will have the information available to respond to requests from users, owners, and operators of the BES. The drafting team believes that including this requirement in the standard or collecting the data via Section 1600 are equally effective ways to address the directive. The drafting team has elected to address the directive within the standard.		
IRC Standards Review Committee	No	While we don't necessarily have an issue with the equipment owner communicating these relay limited circuits to the Regional Entities, we don't believe this is needed for reliability and therefore it should not be included in the reliability standard. Given that it is unclear what the information will even be used for, if it will be needed long-term, and that it is likely will not change much, if at all, from year to year, we believe a data request through NERC's Rules of Procedure section 1600 would be more appropriate. In that way, we don't have to modify the standard later when NERC and the Regions determine they don't need the data annually. Note: CAISO does not sign on to the above comments.
Response: Thank you for your comment. The drafting team believes that including this requirement in the standard or collecting the data via Section 1600 are equally effective ways to address the directive. The drafting team has elected to address the directive within the standard.		
Tennessee Valley Authority	Yes	
New York Power Authority	Yes	
Manitoba Hydro	Yes	
Lakeland Electric	Yes	
NIPSCO	No	We believe the R1 criterion 12 is needed- but the reporting requirement is not.
Response: Thank you for your comment. Requirement R5 (reporting requirement to which you refer) has been revised to require an updated list and the accompanying measure has been modified to indicate that the updated list may either be a full list or a list of incremental changes to the previous list. The drafting team believes that an annual update of the list is sufficient to satisfy the reliability goals of this requirement. The Regional Entity (RE), via the delegation agreements, is a part of the ERO; thus, by submitting the information to the RE, the ERO will have the information available to respond to requests from		

Organization	Yes or No	Question 4 Comment
users, owners, and operators of the BES.		
Western Area Power Administration	Yes	
Minnkota Power Cooperative, Inc.	Yes	
Duke Energy	Yes	
Kansas City Power & Light	No	While we don't necessarily have an issue with the equipment owner communicating these relay limited circuits to the Regional Entities, we don't believe this is needed for reliability and therefore it should not be included in the reliability standard. Given that it is unclear what the information will even be used for, if it will be needed long-term, and that it is likely will not change much, if at all, from year to year, we believe a data request through NERC's Rules of Procedure section 1600 would be more appropriate. In that way, we don't have to modify the standard later when NERC and the Regions determine they don't need the data annually.
Response: Thank you for your comment. The requirement has been revised to require an updated list and the accompanying measure has been modified to indicate that the updated list may either be a full list or a list of incremental changes to the previous list. The drafting team believes that an annual update of the list is sufficient to satisfy the reliability goals of this requirement. The Regional Entity (RE), via the delegation agreements, is a part of the ERO; thus, by submitting the information to the RE, the ERO will have the information available to respond to requests from users, owners, and operators of the BES.		
American Transmission Company	Yes	
Orange and Rockland Utilities, Inc.	Yes	
City of Jacksonville Beach, FL dba/Beaches Energy Services	No	No, once again, that is way too frequent and creates another unnecessary burden for record keeping. It should be a much longer time criteria, say 5 years, with a requirement that if there is a CHANGE, the information is sent to the PC, TO and RC.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. The requirement has been revised to require an updated list and the accompanying measure has been modified to indicate that the updated list may either be a full list or a list of incremental changes to the previous list. The drafting team believes that an annual update of the list is sufficient to satisfy the reliability goals of this requirement. The Regional Entity (RE), via the delegation agreements, is a part of the ERO; thus, by submitting the information to the RE, the ERO will have the information available to respond to requests from users, owners, and operators of the BES.		
American Electric Power	Yes	
Nebraska Public Power District	Yes	
Great River Energy	No	While we don't necessarily have an issue with the equipment owner communicating these relay limited circuits to the Regional Entities, we don't believe this is needed for reliability and therefore it should not be included in the reliability standard. Given that it is unclear what the information will even be used for, if it will be needed long-term, and that it is likely will not change much, if at all, from year to year, we believe a data request through NERC's Rules of Procedure section 1600 would be more appropriate. In that way, we don't have to modify the standard later when NERC and the Regions determine they don't need the data annually.
Response: Thank you for your comment. The requirement has been revised to require an updated list and the accompanying measure has been modified to indicate that the updated list may either be a full list or a list of incremental changes to the previous list. The drafting team believes that an annual update of the list is sufficient to satisfy the reliability goals of this requirement. The Regional Entity (RE), via the delegation agreements, is a part of the ERO; thus, by submitting the information to the RE, the ERO will have the information available to respond to requests from users, owners, and operators of the BES.		
Independent Electricity System Operator	Yes	
Northeast Utilities	Yes	
CenterPoint Energy	No	CenterPoint Energy disagrees with providing a list, as we cannot see any need and do not expect the Regional Entity would have any use for this information. In discussions with Regional Entity personnel, they were unsure of what use they would have for this information.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. The requirement has been revised to require an updated list and the accompanying measure has been modified to indicate that the updated list may either be a full list or a list of incremental changes to the previous list. The drafting team believes that an annual update of the list is sufficient to satisfy the reliability goals of this requirement. The Regional Entity (RE), via the delegation agreements, is a part of the ERO; thus, by submitting the information to the RE, the ERO will have the information available to respond to requests from users, owners, and operators of the BES.		
New York Independent System Operator	Yes	
Oncor Electric Delivery Company LLC	No	Oncor feels that the Requirement R5 is too cumbersome for the Registered Entities who have to, every 12 to 15 months, provide the Regional Entity a list of all the facilities that under Requirement R1 criterion 12 are limited by the requirement to adequately protect the transmission line and cannot meet loadablity. It would better for the Registered Entities to provide a one time list to its Regional Entity and then provide to the Regional Entity any additions or deletions to the list no more than 30 days following any changes to the relaying what would remove or add a transmission line to the list.
Response: Thank you for your comment. The requirement has been revised to require an updated list and the accompanying measure has been modified to indicate that the updated list may either be a full list or a list of incremental changes to the previous list. The drafting team believes that an annual update of the list is sufficient to satisfy the reliability goals of this requirement. The Regional Entity (RE), via the delegation agreements, is a part of the ERO; thus, by submitting the information to the RE, the ERO will have the information available to respond to requests from users, owners, and operators of the BES.		
Consolidated Edison Co. of NY, Inc.	Yes	
Ameren	No	Given that protective relaying equipment is already covered as one component in developing ratings in standards FAC-008-1 and FAC-009-1, it is not clear that there is a reliability based need for the information required to be provided in Requirement R5. Therefore, this requirement should be removed from the proposed standard.
Response: Thank you for your comment.		

Organization	Yes or No	Question 4 Comment
The requirement has been revised to require an updated list and the accompanying measure has been modified to indicate that the updated list may either be a full list or a list of incremental changes to the previous list. The drafting team believes that an annual update of the list is sufficient to satisfy the reliability goals of this requirement. The Regional Entity (RE), via the delegation agreements, is a part of the ERO; thus, by submitting the information to the RE, the ERO will have the information available to respond to requests from users, owners, and operators of the BES. FAC-008 and FAC-009 do not address this issue. FAC-009 requires transmitting the Facility Rating, whereas PRC-023-2 requires notification when the relay loadability is based on established relay settings.		
National Grid	Yes	
ERCOT ISO	No	
MidAmerican Energy	No	While we don't necessarily have an issue with the equipment owner communicating these relay limited circuits to the Regional Entities, we don't believe this is needed for reliability and therefore it should not be included in the reliability standard. Given that it is unclear what the information will even be used for, if it will be needed long-term, and that it is likely will not change much, if at all, from year to year, we believe a data request through NERC's Rules of Procedure section 1600 would be more appropriate. In that way, we don't have to modify the standard later when NERC and the Regions determine they don't need the data annually.
Response: Thank you for your comment. The requirement has been revised to require an updated list and the accompanying measure has been modified to indicate that the updated list may either be a full list or a list of incremental changes to the previous list. The drafting team believes that an annual update of the list is sufficient to satisfy the reliability goals of this requirement. The Regional Entity (RE), via the delegation agreements, is a part of the ERO; thus, by submitting the information to the RE, the ERO will have the information available to respond to requests from users, owners, and operators of the BES.		
Xcel Energy	Yes	

5. *Requirement R6 requires each Planning Coordinator to apply the criteria in Attachment B to determine which transmission Elements must comply with this standard. Do you agree with the requirement included in Requirement R6? If not, please explain and provide specific suggestions for improvement.*

Summary Consideration: In response to Question 5, stakeholders who responded to this question were fairly evenly divided with about half indicating support for Requirement R6 and about half indicating disagreement with some aspect of the proposed requirement.

The drafting team removed parts 6.1 and 6.2 from Requirement R6 to avoid redundancy with the Applicability section and Attachment B. Within the Applicability section and Attachment B, a number of modifications were made based on industry comments to improve clarity.

The drafting team replaced the phrase “critical for the purposes of the Compliance Registry” with text from ¶60 of Order No. 733, which references text in section III.d.2 of the NERC Statement of Compliance Registry Criteria. So the second category of circuits to be evaluated now refers to transmission lines and transformers operated below 100 kV “that are included on a critical facilities list defined by the Regional Entity.”

The drafting team believes that to maintain consistency with the NERC Statement of Compliance Registry Criteria, should the Regional Entity develop a critical facilities list for application of the Compliance Registry Criteria, the Planning Coordinator would have to apply the criteria in Attachment B to determine for which of the circuits on the list the applicable entities must comply with the standard.

While the drafting team acknowledges there is no requirement for the Regional Entity to provide the list, the drafting team believes the Regional Entity will make a critical facilities list available as it is necessary for other entities to have this information to support reliable operation of the interconnected transmission grid.

The drafting team understands the double jeopardy concern and has deleted Requirement R7 to resolve this concern.

The Effective Dates section of the standard was modified to address the timeline in which Facility owners must comply with Requirements R1 through R5 when the Planning Coordinator identifies a circuit for which the Facility owner must comply with the standard.

Organization	Yes or No	Question 5 Comment
Electric Market Policy	Yes	
Potomac Holdings Inc & Affiliates	Yes	

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council	Yes	
Pacific Northwest Small Public Power Utility Comment Group	Yes	
Tri-State G & T System Protection	Yes	
Midwest ISO Standards Collaborators	No	1) It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV that are part of the Bulk Electric System. This information is not readily available and there is no requirement for the Regional Entity to communicate it to them. Thus, inaction by the auditor (i.e. Regional Entity) could actually cause the Planning Coordinator to violate this requirement. This is clearly a conflict of interest. 2) Why does the Planning Coordinator need to identify which circuits are identified per criteria B4? There is no justification given for this need and there is nothing else that appears to require action as a result of this information. Thus, it is purely administrative and should be removed. Registered entities should never be subject to potential sanctions for violations of purely administrative portions of requirements. 3) Why does the Planning Coordinator need to provide this information to the Reliability Coordinator? There is nothing for the Reliability Coordinator to do with the information. The Reliability Coordinator only needs to be informed if equipment becomes derated and then that should occur through the normal communication of ratings per FAC-009-1.

Response: Thank you for your comment.

1) If the Regional Entity develops a critical facilities list, the drafting team believes the Regional Entity will make this information available as it is necessary for other entities to have this information to support reliable operation of the interconnected transmission grid.

2) The criteria in Attachment B provide a consistent methodology for Planning Coordinators to perform the determination presently assigned in Requirement R3 of PRC-023-1 (now Requirement R6 in PRC-023-2). This requirement supports the reliability purpose of this standard by identifying the circuits below 200 kV which could lead to cascading outages, if Protection Systems are not set according to the relay loadability requirements. The action required as a result of this determination is stated in Requirement R6: for circuits identified by the Planning Coordinator, the Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5.

3) This portion of this requirement is included in PRC-023-1 and was not modified in PRC-023-2.

Organization	Yes or No	Question 5 Comment
MRO's NERC Standards Review Subcommittee	No	1) It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV that are part of the Bulk Electric System. This information is not readily available and there is no requirement for the Regional Entity to communicate it to them. Thus, inaction by the auditor (i.e. Regional Entity) could actually cause the Planning Coordinator to violate this requirement. This is clearly a conflict of interest. 2) Why does the Planning Coordinator need to identify which circuits are identified per criteria B4? There is no justification given for this need and there is nothing else that appears to require action as a result of this information. Thus, it is purely administrative and should be removed. Registered entities should never be subject to potential sanctions for violations of purely administrative portions of requirements. 3) Why does the Planning Coordinator need to provide this information to the Reliability Coordinator? There is nothing for the Reliability Coordinator to do with the information. The Reliability Coordinator only needs to be informed if equipment becomes derated and then that should occur through the normal communication of ratings per FAC-009-1.
Response: Thank you for your comment. 1) If the Regional Entity develops a critical facilities list, the drafting team believes the Regional Entity will make this information available as it is necessary for other entities to have this information to support reliable operation of the interconnected transmission grid. 2) The criteria in Attachment B provide a consistent methodology for Planning Coordinators to perform the determination presently assigned in Requirement R3 of PRC-023-1 (now Requirement R6 in PRC-023-2). This requirement supports the reliability purpose of this standard by identifying the circuits below 200 kV which could lead to cascading outages, if Protection Systems are not set according to the relay loadability requirements. The action required as a result of this determination is stated in Requirement R6: for circuits identified by the Planning Coordinator, the Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. 3) This portion of this requirement is included in PRC-023-1 and was not modified in PRC-023-2.		
Santee Cooper	Yes	
FirstEnergy	Yes	While we agree with the intent of Requirement R6, FE believes improvements can be made to simplify and clarify the R6 text. a. Items 6.1 and 6.2 can be removed as they are duplicative with the two bulleted items listed at the forefront of Attachment B. b. Item 6.3 is awkwardly written based on the circular reference to R6. Its suggested that Item 6.3 be re-written to say “Maintain a list of transmission Facilities operated below 200kV and deemed applicable to the

Organization	Yes or No	Question 5 Comment
		PRC-023 standard per application of Attachment B” c. Requirement R6 and Attachment B text seem to mix and interchange references to Glossary of Term definitions “Elements” and “Facility”, although facility(ies) is often not capitalized, such that they are used synonymously. As one example R6 indicates “...determine which transmission Elements must comply with this standard ...” compared to Attachment B which says “... to determine the facilities which must comply with this standard.” Sub items of R6 refer to keeping a list of “facilities” and not “Elements” as referenced in the parent R6 requirement. For greater consistency we suggest the use of the term “Facility(ies)” over “Element”. d. If the team believes a reference to a Planning Coordinator only needing to cover transmission facilities within their footprint is needed, such as used in items 6.1 and 6.2 which are proposed for removal, the team could revise the parent R6 text to read “ ... to determine which transmission Elements [Facilities] in its Planning Coordinator area must comply with this standard.” e. Replace the word “year” in item 6.5 with “planning study year”. It’s also recommended that the same change occur in R7, to better clarify what “year” is referring to in R7.
Response: Thank you for your comment. a) The standard text has been modified as you suggest. b) The standard text has been modified as you suggest. c) The drafting team has reviewed these terms for consistent usage throughout the standard. The drafting team now uses the NERC glossary term “Facility” consistently throughout the document. d) Although parts 6.1 and 6.2 have been removed as suggested, the drafting team has made changes in Requirement R6 that are consistent with the intent of this comment. e) The standard text has been modified as you suggest in Requirement R6. Requirement R7 has been deleted in response to other comments.		
IRC Standards Review Committee	No	1) Wording for R 6.2 is confusing. Revise to clearly state the intent of the requirement is for registered entities to report to Regional Entities those facilities below 100KV that the requirements should apply to and that the requirement for Regional Entities is only to make that list available. 2) It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV that are part of the Bulk Electric System. This information is not readily available and there is no requirement for the Regional Entity to communicate it to them. Thus, inaction by the auditor (i.e. Regional Entity) could actually cause the Planning Coordinator to violate this requirement. This is clearly a conflict of interest. 3) Why does the Planning Coordinator need to identify which circuits are identified per criteria B4? There is

Organization	Yes or No	Question 5 Comment
		no justification given for this need and there is nothing else that appears to require action as a result of this information. Thus, it is purely administrative and should be removed. Registered entities should never be subject to potential sanctions for violations of purely administrative portions of requirements. 4) Why does the Planning Coordinator need to provide this information to the Reliability Coordinator? There is nothing for the Reliability Coordinator to do with the information. The Reliability Coordinator only needs to be informed if equipment becomes derated and then that should occur through the normal communication of ratings per FAC-009-1. Note: CAISO does not sign on to the above comments.
Response: Thank you for your comment. 1) The drafting team has eliminated parts 6.1 and 6.2 from Requirement R6. The drafting team understands that repeating this information in Requirement R6 and in Attachment B is redundant and potentially confusing. In addition, the drafting team has revised the text in Attachment B to more clearly convey the intent. 2) If the Regional Entity develops a critical facilities list, the drafting team believes the Regional Entity will make this information available as it is necessary for other entities to have this information to support reliable operation of the interconnected transmission grid. 3) The criteria in Attachment B provide a consistent methodology for Planning Coordinators to perform the determination presently assigned in Requirement R3 of PRC-023-1 (now Requirement R6 in PRC-023-2). This requirement supports the reliability purpose of this standard by identifying the circuits below 200 kV which could lead to cascading outages, if Protection Systems are not set according to the relay loadability requirements. The action required as a result of this determination is stated in Requirement R6: for circuits identified by the Planning Coordinator, the Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5. 4) This portion of this requirement is included in PRC-023-1 and was not modified in PRC-023-2.		
Tennessee Valley Authority	No	1) Per Requirement R6 criterion 2, the Planning Coordinator is better suited to analyze the subsystem and its effect on the BES than the Regional Entity, so “Regional Entity” should be replaced with “Planning Coordinator”. 2) Please also see Question 8 comment concerning the use of “flowgate” in Attachment B section B1.
Response: Thank you for your comments. 1) This criterion has been removed from the PRC-023-2 standard. 2) Please see our response to your comment in Question 8.		
New York Power Authority	Yes	

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td>Manitoba Hydro</td><td>No</td><td>1. We don’t think that the system would change that fast to warrant the additional work of conducting an assessment every year. The entities involved have 24 months to make the necessary changes as given in R7. If an annual assessment is required then this should be added as a requirement to TPL-001-2 rather than buried in PRC-023. It would be more efficient to perform an assessment over the 10-year planning horizon every 2-3 years. Critical facilities identified in the assessment can be monitored in the in-between years to ensure construction schedules are on track and the need is still there. One initial detailed assessment of the current year facilities could be done but then the assessment should be more focused on additions and changes.

2. The VSLs for R6 are too severe. The system doesn’t change that rapidly and getting the list to the entities involved before 60 days does not impact reliability given that they have 2 years to comply with changes.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.

1. The drafting team intended that an assessment be performed each year, but that the power flow analyses used to support the assessment need not be performed unless material changes to the system have occurred since the last assessment. The drafting team has added a footnote to criterion B4 to clarify this intent.

The drafting team believes the one-to-five-year planning horizon is more appropriate for this requirement and has added this clarification in criterion B4. The one-to-five-year planning horizon provides adequate lead-time for identifying circuits for which applicable entities must comply with PRC-023, while reducing the level of uncertainty associated with the model compared to the 10-year planning horizon.

2. The VSL was approved as part of PRC-023-1 and has not been modified in PRC-023-2.</td></tr>
<tr><td>Lakeland Electric</td><td>No</td><td>In R6.2 the phrase “for the purposes of the Compliance Registry and” is used. The same phrase is also used under Applicability in sections 4.2.3 and 4.2.6. What is the purpose of this phrase in these sections? I do not think that the phrase has any value in these locations. The phrase is also used in the PRC-023 - Attachment B in the second bullet under “Criteria”. It seems to imply that if a circuit is identified as a critical facility that fact could be used to drive registration of an entity that otherwise may not require registration. If that is the intent then I would suggest modifying the phrase in the attachment to “that may require entity registration in the Compliance Registry “</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

The phrase “for the purposes of the Compliance Registry” could include a circuit identified as a critical facility that could used to drive registration of an entity that otherwise may not require registration. The drafting team has removed parts 6.1 and 6.2 from Requirement R6 to avoid redundancy with Applicability section and Attachment B. Within the Applicability section and Attachment B, a number of modifications have been made based on industry comments to improve clarity. The drafting team has replaced the phrase “critical for the purposes of the Compliance Registry” with text from ¶60 of Order No. 733, which references text in section III.d.2 of the NERC Statement of Compliance Registry Criteria. So the second category of circuits to be evaluated now refers to transmission lines and</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
transformers operated below 100 kV “that are included on a critical facilities list defined by the Regional Entity.”		
NIPSCO	No	Only the owner or TO GO DP should apply the criteria - which can be then reported to the PC
Response: Thank you for your comment. The drafting team believes the Planning Coordinator is the NERC Functional Model entity with the wide-area view and study expertise necessary to perform the assessment in Attachment B. The drafting team also notes that assigning this responsibility solely to the Planning Coordinator is consistent with the approved PRC-023-1 and FERC Order No. 733.		
Western Area Power Administration	No	Feel that NERC is delving too much into the technical details. Should allow Planning Coordinators to establish their own study methodologies.
Response: Thank you for your comment. The drafting team believes it is important that all Planning Coordinators utilize a consistent methodology for identifying the Facilities below 200 kV for which the applicable entities must comply with PRC-023-2. FERC, in Order No. 733, identified concerns with lack of a consistent methodology and directed development of a consistent methodology for inclusion in PRC-023.		
Minnkota Power Cooperative, Inc.	No	Many facilities with voltages between 100kV and 200kV will only impact a well-defined local load region if they trip. There is no risk of cascading outages beyond the local load region. The criteria in Attachment B should allow these types of facilities to be dismissed from evaluation.
Response: Thank you for your comment. The criteria in Attachment B were selected to identify circuits that present a risk of cascading outages if relay loadability requirements are not met. The drafting team has added to some of the criteria that the Planning Coordinator shall consult with the Facility owner when performing its assessment to provide the Facility owner an opportunity for input into the assessment. Additionally, an appeals process will be included in the NERC Rules of Procedure so that a Facility owner may appeal a decision in the event it believes a circuit is incorrectly identified by the Planning Coordinator.		
Duke Energy	No	1) R6.1 and R6.2 unnecessarily duplicate the first part of Attachment B, and should be deleted from R6. 2) R6.3 and R6.4 are both associated with maintaining the list and should be combined into a separate requirement (new R7), with its own VRF and VSLs. Including the year for a facility should apply to all the criteria, not just B4. Suggested wording for new R7: “Maintain a list of circuits that must comply with this standard due to meeting Attachment B criteria. For each circuit, include the applicable criteria and the year studied for which the criteria first applies, when a facility is added to the list.”

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>3) R6.5 should become a new R8 with its own VRF and VSLs. No wording changes needed.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1) The standard text has been modified as you suggest.
2) The drafting team believes that it is appropriate to include details regarding maintenance of the list as a part of Requirement R6 consistent with the existing standard PRC-023-1. While the drafting team disagrees that parts 6.3 and 6.4 should become a separate requirement, the drafting team has combined these into one part of Requirement R6 consistent with the commenters recommendation. The combined text, now part 6.1, reads:
“6.1 Maintain a list of circuits subject to PRC-023-2 per application of Attachment B, including identification of the first calendar year in which any criterion in Attachment B applies.”
3) The structure of the standard text within R6 including the approved VRFs and VSLs is similar to R3 in PRC-023-1 and is therefore beyond the scope of the project to modify.</td></tr>
<tr><td>Kansas City Power & Light</td><td>No</td><td>1) It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV that are part of the Bulk Electric System. This information is not readily available and there is no requirement for the Regional Entity to communicate it to them. Thus, inaction by the auditor (i.e. Regional Entity) could actually cause the Planning Coordinator to violate this requirement. This is clearly a conflict of interest.
2) Why does the Planning Coordinator need to identify which circuits are identified per criteria B4? There is no justification given for this need and there is nothing else that appears to require action as a result of this information. Thus, it is purely administrative and should be removed. Registered entities should never be subject to potential sanctions for violations of purely administrative portions of requirements.
3) Why does the Planning Coordinator need to provide this information to the Reliability Coordinator? There is nothing for the Reliability Coordinator to do with the information. The Reliability Coordinator only needs to be informed if equipment becomes derated and then that should occur through the normal communication of ratings per FAC-009-1.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1) If the Regional Entity develops a critical facilities list, the drafting team believes the Regional Entity will make this information available as it is necessary for other entities to have this information to support reliable operation of the interconnected transmission grid.
2) The criteria in Attachment B provide a consistent methodology for Planning Coordinators to perform the determination presently assigned in Requirement R3 of PRC-023-1 (now Requirement R6 in PRC-023-2). This requirement supports the reliability purpose of this standard by identifying the circuits below 200 kV which could lead to cascading outages, if Protection Systems are not set according to the relay loadability requirements. The action required as a result of this determination is stated in Requirement R6: for circuits identified by the Planning Coordinator, the Transmission Owners, Generator Owners, and Distribution</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
Providers must comply with Requirements R1 through R5. 3) This portion of this requirement is included in PRC-023-1 and was not modified in PRC-023-2.		
American Transmission Company	Yes	Except ATC is recommending the following wording change for Requirement R 6.2 which provides clarification on the application of the criteria: “Apply the criteria to the following Elements in its Planning Coordinator Area, if any: those transmission lines operated below 100 kV and those transformers with low voltage terminal connections below 100 kV that the Regional Entity has identified as critical facilities for the purposes of the Compliance Registry.”
Response: Thank you for your comment. The drafting team has removed parts 6.1 and 6.2 from Requirement R6 to avoid redundancy with Attachment B. Within Attachment B, a number of modifications have been made based on industry comments to improve clarity. The drafting team believes these modifications address the commenter’s concern.		
Orange and Rockland Utilities, Inc.	Yes	
City of Jacksonville Beach, FL dba/Beaches Energy Services	Yes	
American Electric Power	No	The wording under Sections 4.2.3, 4.2.6, 6.2, and the applicability portion of Attachment B needs to be made consistent to avoid any misinterpretations and confusion.- Section 4.2.3 - Delete the portion that reads “... and the Planning Coordinator has determined are required to comply with this standard” for this section to read the same as the associated sentence under the applicability portion of Attachment B.- Section 4.2.6 - Same comment as Section 4.2.3 (above).- Section 6.2 - Reword to read: “Apply the criteria to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that the Regional Entity has identified as critical for the purposes of the Compliance Registry.”
Response: Thank you for your comment. The drafting team agrees that inconsistency between these sections of the standard will lead to confusion. The drafting team has removed parts 6.1 and 6.2 from Requirement R6 to avoid redundancy, and has revised the Applicability section and Attachment B based on industry comments to provide consistency and clarity.		
Nebraska Public Power District	Yes	If attachment B is kept then the PC should determine which transmission elements must comply with the standard.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comment.</td></tr>
<tr><td>Great River Energy</td><td>No</td><td>1) It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV and that are part of the Bulk Electric System. This information is not readily available and there is no requirement for the Regional Entity to communicate it to them. Thus, inaction by the auditor (i.e. Regional Entity) could actually cause the Planning Coordinator to violate this requirement. This is clearly a conflict of interest.
2) Why does the Planning Coordinator need to identify which circuits are identified per criteria B4? There is no justification given for this need and there is nothing else that appears to require action as a result of this information. Thus, it is purely administrative and should be removed. Registered entities should never be subject to potential sanctions for violations of purely administrative portions of requirements.
3) Why does the Planning Coordinator need to provide this information to the Reliability Coordinator? There is nothing for the Reliability Coordinator to do with the information. The Reliability Coordinator only needs to be informed if equipment becomes derated and then that should occur through the normal communication of ratings per FAC-009-1</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1) If the Regional Entity develops a critical facilities list, the drafting team believes the Regional Entity will make this information available as it is necessary for other entities to have this information to support reliable operation of the interconnected transmission grid.
2) The criteria in Attachment B provide a consistent methodology for Planning Coordinators to perform the determination presently assigned in Requirement R3 of PRC-023-1 (now Requirement R6 in PRC-023-2). This requirement supports the reliability purpose of this standard by identifying the circuits below 200 kV which could lead to cascading outages, if Protection Systems are not set according to the relay loadability requirements. The action required as a result of this determination is stated in Requirement R6: for circuits identified by the Planning Coordinator, the Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5.
3) This portion of this requirement is included in PRC-023-1 and was not modified in PRC-023-2.</td></tr>
<tr><td>Independent Electricity System Operator</td><td>No</td><td>We agree that the PC should be held responsible for conducting the annual assessment, but we do not understand the need for including “if the Regional Entity has identified either of these Element types as critical facilities for the purposes of the Compliance Registry” in R6.2. We also do not understand the meaning of “as critical facilities for the purpose of Compliance Registry”. There are established criteria for compliance registry, but we are not aware of what constitutes “critical facilities for the purpose of compliance registry”.
For the purpose of determining compliance with the relay loadability requirements, having the PC to make such an assessment and determination would suffice. If the intent is to limit the facilities to be assessed to</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
		only those that have been identified as “critical facilities for the purpose of compliance registry”, then it implies that those that are not identified are not required to be assessed. This may in fact result in missing some facilities that may be critical from a relay loadability standpoint. Further, the term “critical facilities” is used very loosely in different standards, and can mean very different things for various applications and under various circumstances. We suggest to remove ““if the Regional Entity has identified either of these Element types as critical facilities for the purposes of the Compliance Registry” from the requirement. For the same reason, we suggest the quoted phrase be removed from the Applicability Section, any other requirements in this standard, and Attachment B.
Response: Thank you for your comment. The drafting team has removed parts 6.1 and 6.2 from Requirement R6 to avoid redundancy with Attachment B. Within Attachment B, a number of modifications have been made based on industry comments to improve clarity. The drafting team has replaced the phrase “critical for the purposes of the Compliance Registry” with text from ¶60 of Order No. 733, which references text in section III.d.2 of the NERC Statement of Compliance Registry Criteria. So the second category of circuits to be evaluated now refers to transmission lines and transformers operated below 100 kV “that are included on a critical facilities list defined by the Regional Entity. It is the intent of the drafting team, consistent with the directive in Order No. 733, to only require assessment of circuits operated below 100 kV if they have been identified by the Regional Entity as noted. The drafting team believes circuits that could lead to cascade tripping if relay loadability requirements are not met would be included on a critical facilities list defined by the Regional Entity.		
Northeast Utilities	Yes	
CenterPoint Energy	No	(a) CenterPoint Energy recommends revising R6 to require Planning Coordinators to coordinate with associated Transmission Planners in the determination of which 100 - 200 kV elements must comply with this standard. (b) CenterPoint Energy recommends criterion B5 be deleted, as it is too broad and gives the Planning Coordinator too much discretion in determining other facilities which must comply with this Standard. In the case that criteria B5 is not deleted, CenterPoint Energy recommends that a process be required where Transmission Planners can appeal the inclusion of specific Transmission elements that must comply with this standard. (c) CenterPoint Energy recommends eliminating the un-capitalized term “critical” to remove any confusion with NERC CIP reliability standards. The voluntary NERC relay loadability review in 2006 used the term “operationally significant element” for elements 100 - 200 kV. CenterPoint Energy recommends using “operationally significant” wherever “critical” is used within PRC-023-2.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. (a) The drafting team believes the Planning Coordinator is the NERC Functional Model entity with the wide-area view and study expertise necessary to perform the assessment in Attachment B. The drafting team also notes that assigning this responsibility solely to the Planning Coordinator is consistent with the approved PRC-023-1 and FERC Order No. 733. (b) The drafting team has modified criterion B5 in response to industry comments to require that if the Planning Coordinator selects a circuit based on technical studies or assessments, other than those specified in criteria B1 through B4, that such selection is to be made in consultation with the Facility owner to provide the Facility owner an opportunity for input into the assessment. Additionally, an appeals process will be included in the NERC Rules of Procedure so that a Facility owner may appeal a decision in the event it believes a circuit is incorrectly identified by the Planning Coordinator. (c) The context in which the term "critical" is used is different than in the NERC "Zone 3" and "Beyond Zone 3" reviews. The remaining references to the term critical are in the context of NERC Statement of Compliance Registry Criteria. Rather than using the term "operationally significant," the drafting team has replaced the phrase "critical for the purposes of the Compliance Registry" with text from ¶60 of Order No. 733, which references text in section III.d.2 of the NERC Statement of Compliance Registry Criteria. So the second category of circuits to be evaluated now refers to transmission lines and transformers operated below 100 kV "that are included on a critical facilities list defined by the Regional Entity." The drafting team made corresponding modifications to the Applicability section.		
New York Independent System Operator	No	Wording for R6.2 is confusing. It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV. This information is not readily available and there is no requirement for the Regional Entity to communicate it to them. Revise to clearly state the intent of the requirement is for registered entities to report to Regional Entities those applicable facilities below 100kV and that the requirement for Regional Entities is only to make that list available. There is no justification given in R6.4 for the need to identify facilities for which criterion B4 applies and there is no further required action as a result of this information. Thus, it is purely administrative and should be removed. Registered entities should never be subject to potential sanctions for violations of purely administrative portions of requirements.
Response: Thank you for your comment. The drafting team has removed parts 6.1 and 6.2 from Requirement R6 to avoid redundancy with Attachment B. Within Attachment B, a number of modifications have been made based on industry comments to improve clarity. The drafting team has replaced the phrase "critical for the purposes of the Compliance Registry" with text from ¶60 of Order No. 733, which references text in section III.d.2 of the NERC Statement of Compliance Registry Criteria. So the second category of circuits to be evaluated now refers to transmission lines and transformers operated below 100 kV "that are included on a critical facilities list defined by the Regional Entity." The drafting team believes the Regional Entity will make this information available as it is necessary for other entities to have this information to support reliable operation of the interconnected transmission grid.		
Oncor Electric Delivery Company LLC		

Organization	Yes or No	Question 5 Comment
Consolidated Edison Co. of NY, Inc.	Yes	
Ameren	No	Section 6.2 is unclear and seems arbitrary in the statement 'if the Regional Entity has indentified either of these Element types as critical facilities for the purpose of the Compliance registry'. A clear test is lacking.
Response: Thank you for your comment. The drafting team has removed parts 6.1 and 6.2 from Requirement R6 to avoid redundancy, and has revised the Applicability section and Attachment B (which used the same phrase) based on industry comments to provide clarity. The drafting team has replaced the phrase "critical for the purposes of the Compliance Registry" with text from ¶60 of Order No. 733, which references text in section III.d.2 of the NERC Statement of Compliance Registry Criteria. So the second category of circuits to be evaluated now refers to transmission lines and transformers operated below 100 kV "that are included on a critical facilities list defined by the Regional Entity." The test by which the Regional Entity may make this determination is outside the scope of this standard.		
National Grid	Yes	
ERCOT ISO	No	ERCOT ISO is unclear, as to what is meant by the reference to the Compliance Registry. Additionally, ERCOT ISO feels the Regional Entities are not the appropriate entities to declare which elements (below 100kV) should be considered critical. For 6.2 and Attachment B, ERCOT ISO suggests completely removing the existing language pertaining to facilities operated below 100kV.
Response: Thank you for your comment. The drafting team believes it would be inappropriate to remove all language pertaining to facilities operated below 100 kV, as Order No. 733 directs consideration of such facilities and the NERC Statement of Compliance Registry Criteria permits applicability of NERC Reliability Standards to certain facilities operated below 100 kV. The drafting team has removed parts 6.1 and 6.2 from Requirement R6 to avoid redundancy, and has revised the Applicability section and Attachment B based on industry comments to provide clarity. The drafting team has replaced the phrase "critical for the purposes of the Compliance Registry" with text from ¶60 of Order No. 733, which references text in section III.d.2 of the NERC Statement of Compliance Registry Criteria. So the second category of circuits to be evaluated now refers to transmission lines and transformers operated below 100 kV "that are included on a critical facilities list defined by the Regional Entity."		
MidAmerican Energy	No	1) Sections 4.2.2, 4.2.3, 4.2.6, R6, and Attachment B needs to be modified with a superior alternative than the FERC recommendation to assign the PC the responsibility to determine a sub-200 kV critical facility test. NERC needs to re-assign this to the Transmission Owners and Operators as the entities that properly perform transmission planning analysis. The PC's aren't the proper entities that understand and perform the proper analyses. Therefore the superior alternative is to re-assign the responsibility to the party that understand what is truly critical and why. At a minimum Transmission Owners and / or Operators should be added to ensure that the entities that best understand the operation of the electric

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>grid. It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV that are part of the Bulk Electric System. This information is not readily available and there is no requirement for the Regional Entity to communicate it to them. Thus, inaction by the auditor (i.e. Regional Entity) could actually cause the Planning Coordinator to violate this requirement. This is clearly a conflict of interest.
2) Why does the Planning Coordinator need to identify which circuits are identified per criteria B4? There is no justification given for this need and there is nothing else that appears to require action as a result of this information. Thus, it is purely administrative and should be removed. Registered entities should never be subject to potential sanctions for violations of purely administrative portions of requirements.
3) Why does the Planning Coordinator need to provide this information to the Reliability Coordinator? There is nothing for the Reliability Coordinator to do with the information. The Reliability Coordinator only needs to be informed if equipment becomes derated and then that should occur through the normal communication of ratings per FAC-009-1.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
1) The drafting team believes the Planning Coordinator is the NERC Functional Model entity with the wide-area view and study expertise necessary to perform the assessment in Attachment B. The responsibilities defined in the NERC Function Model for the Transmission Operator and Transmission Owner are not consistent with skills necessary to perform these assessments. The drafting team also notes that assigning this responsibility solely to the Planning Coordinator is consistent with the approved PRC-023-1 and FERC Order No. 733.
The drafting team has replaced the phrase “critical for the purposes of the Compliance Registry” with text from ¶60 of Order No. 733, which references text in section III.d.2 of the NERC Statement of Compliance Registry Criteria. So the second category of circuits to be evaluated now refers to transmission lines and transformers operated below 100 kV “that are included on a critical facilities list defined by the Regional Entity.” The drafting team believes the Regional Entity will make this information available as it is necessary for other entities to have this information to support reliable operation of the interconnected transmission grid.
2) The criteria in Attachment B provide a consistent methodology for Planning Coordinators to perform the determination presently assigned in Requirement R3 of PRC-023-1 (now Requirement R6 in PRC-023-2). This requirement supports the reliability purpose of this standard by identifying the circuits below 200 kV which could lead to cascading outages, if Protection Systems are not set according to the relay loadability requirements. The action required as a result of this determination is stated in Requirement R6: for circuits identified by the Planning Coordinator, the Transmission Owners, Generator Owners, and Distribution Providers must comply with Requirements R1 through R5.
3) This portion of this requirement is included in PRC-023-1 and was not modified in PRC-023-2.</td></tr>
<tr><td>Xcel Energy</td><td>Yes</td><td></td></tr>
</table>

6. *Requirement R7 requires the Registered Entities to implement Requirement R1, Requirement R2, Requirement R3, Requirement R4, and Requirement R5 for each facility that the Planning Coordinator added to the list of facilities that must comply with this standard (per Requirement R6) by certain dates following notification by the Planning Coordinator. Do you agree with Requirement R7? If not, please explain and provide specific suggestions for improvement.*

Summary Consideration: In response to Question 6, most stakeholders indicated support for Requirement R7, but there were some strong objections.

Two significant items were addressed and resolved by the drafting team in response to comments received from the industry. First, the drafting team understands the double jeopardy concern between R1 through R5 and Requirement R7 and therefore deleted Requirement R7. The Effective Dates section has been modified to address the timeframe in which Facility owners must comply with Requirements R1 through R5 when the Planning Coordinator identifies a circuit for which the Facility owner must comply with the standard.

Secondly, the drafting team has considered a number of comments regarding the implementation timeframe for the standard requirements and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1.

Organization	Yes or No	Question 6 Comment
Electric Market Policy	Yes	
Potomac Holdings Inc & Affiliates	Yes	
Northeast Power Coordinating Council	Yes	
Pacific Northwest Small Public Power Utility Comment Group	Yes	
Tri-State G & T System Protection	Yes	
Midwest ISO Standards Collaborators	No	We do not believe that R7 is needed. The applicability section of the standard is clear that the standard applies to those circuits identified in R6. This requirement could be construed as potential for double jeopardy

Organization	Yes or No	Question 6 Comment
		because failure to comply with Requirements 1-5 would represent a violation of Requirement 7 also.
Response: Thank you for your comment. The drafting team understands the double jeopardy concern and has deleted Requirement R7. The Effective Dates section has been modified to address the timeframe in which Facility owners must comply with Requirements R1 through R5 when the Planning Coordinator identifies a circuit for which the Facility owner must comply with the standard.		
MRO's NERC Standards Review Subcommittee	No	We do not believe that R7 is needed. The applicability section of the standard is clear that the standard applies to those circuits identified in R6. This requirement could be construed as potential for double jeopardy because failure to comply with Requirements 1 through 5 would represent a violation of both Requirement 7 and Requirements 1 through 5.
Response: Thank you for your comment. The drafting team understands the double jeopardy concern and has deleted Requirement R7. The Effective Dates section has been modified to address the timeframe in which Facility owners must comply with Requirements R1 through R5 when the Planning Coordinator identifies a circuit for which the Facility owner must comply with the standard.		
Santee Cooper	Yes	
Bonneville Power Administration	No	BPA feels the applicable date descriptions are too confusing and would like to see more clarity and simplification.
Response: Thank you for your comment. The referenced date descriptions are consistent with the phraseology used in existing approved NERC standards.		
FirstEnergy	Yes	We support the minimum 24 month implementation timeframe because a responsible entity will need sufficient time to allow for any capital expenditures that may be required due to additional facilities identified by the Planning Coordinator.
Response: Thank you for your comment. The drafting team notes that in response to other comments, and for consistency with PRC-023-1, the implementation time frame has been extended to 39 months.		

Organization	Yes or No	Question 6 Comment
IRC Standards Review Committee	No	We do not believe that R7 is needed. The applicability section of the standard is clear that the standard applies to those circuits identified in R6. This requirement could be construed as potential for double jeopardy because failure to comply with Requirements 1-5 for represent a violation of both Requirement 7 and Requirement 1-5.
Response: Thank you for your comment. The drafting team understands the double jeopardy concern and has deleted Requirement R7. The Effective Dates section has been modified to address the timeline in which Facility owners must comply with Requirements R1 through R5 when the Planning Coordinator identifies a circuit for which the Facility owner must comply with the standard.		
Tennessee Valley Authority	Yes	
New York Power Authority	Yes	
Manitoba Hydro	No	The effective date should not be a uniform date, it should be dependent on the number of circuits that have been identified and determined as critical circuits for an individual utility.
Response: Thank you for your comment. The drafting team has considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1.		
Lakeland Electric	Yes	
NIPSCO	No	We believe only the owners of facilities should have this requirement, not the PC
Response: Thank you for your comment. The drafting team believes that the standard requirement only applies to the owners of the facilities. However, the drafting team notes that Requirement R7 has been deleted in response to other comments.		
Western Area Power Administration	Yes	
Minnkota Power Cooperative,	Yes	

Organization	Yes or No	Question 6 Comment
Inc.		
Duke Energy	No	Since the Attachment B criteria are applied beyond the operating horizon, R7 should be rewritten (and also renumbered as R9). Suggested wording: " Each Transmission Owner, Generator Owner, and Distribution Provider shall implement Requirement R1, Requirement R2, Requirement R3, Requirement R4, and Requirement R5 for each facility that is added to the Planning Coordinator's list of facilities that must comply with this standard pursuant to Requirement R6, by the first day of the first calendar quarter of the year in which Attachment B criteria first apply. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]
Response: Thank you for your comment. The drafting team notes that Requirement R7 has been deleted in response to other comments. The Effective Dates section has been modified to address the timeframe in which Facility owners must comply with Requirements R1 through R5 when the Planning Coordinator identifies a circuit for which the Facility owner must comply with the standard.		
Kansas City Power & Light	No	We do not believe that R7 is needed. The applicability section of the standard is clear that the standard applies to those circuits identified in R6. This requirement could be construed as potential for double jeopardy because failure to comply with Requirements 1-5 for represent a violation of both Requirement 7 and Requirement 1-5.
Response: Thank you for your comment. The drafting team understands the double jeopardy concern and has deleted Requirement R7. The Effective Dates section has been modified to address the timeframe in which Facility owners must comply with Requirements R1 through R5 when the Planning Coordinator identifies a circuit for which the Facility owner must comply with the standard.		
American Transmission Company	No	ATC believes it is difficult to determine without knowing the full scope of work. Until the Planning criteria can be determined, the scope is unknown. Assuming not many assets are added, two years would be a more reasonable amount of time.
Response: Thank you for your comment. The drafting team has considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1.		
Orange and Rockland Utilities, Inc.	Yes	

Organization	Yes or No	Question 6 Comment
City of Jacksonville Beach, FL dba/Beaches Energy Services	Yes	
American Electric Power	No	Need to provide a 60-month timeline to implement the noted requirements for each facility that is added to the Planning Coordinator's initial list of facilities that must comply with this standard, versus the 24-month timeline to implement the noted requirements for each facility that is added to the Planning Coordinator's established list of facilities that must comply with this standard. This is a practical consideration that recognizes the high likelihood that the number of facilities that will be identified during development of the initial list of facilities will be many times greater than the incremental number of facilities that will be identified during the annual assessments and added to the established list of facilities. In addition, need to specify under this requirement whether any facilities that drop off the Planning Coordinator's list of facilities while still within the applicable (60-month or 24-month) implementation timeline must still comply with this standard.
Response: Thank you for your comment. The drafting team has considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1.		
Nebraska Public Power District	Yes	
Great River Energy	No	We do not believe that R7 is needed. The applicability section of the standard is clear that the standard applies to those circuits identified in R6. This requirement could be construed as potential for double jeopardy because failure to comply with Requirements 1 through 5 would represent a violation of both Requirement 7 and Requirements 1 through 5.
Response: Thank you for your comment. The drafting team understands the double jeopardy concern and has deleted Requirement R7. The Effective Dates section has been modified to address the timeframe in which Facility owners must comply with Requirements R1 through R5 when the Planning Coordinator identifies a circuit for which the Facility owner must comply with the standard.		
Independent Electricity System Operator	Yes	
Northeast Utilities	Yes	

Organization	Yes or No	Question 6 Comment
CenterPoint Energy	No	CenterPoint Energy believes Requirement 7 should be deleted from PRC-23-2, as it an Effective Date / Implementation Plan issue. Instead the wording should be included in PRC-023-2 in Effective Dates item 5.5 and within the Implementation Plan.
Response: Thank you for your comment. The drafting team understands the double jeopardy concern and has deleted Requirement R7. The Effective Dates section has been modified to address the timeframe in which Facility owners must comply with Requirements R1 through R5 when the Planning Coordinator identifies a circuit for which the Facility owner must comply with the standard.		
New York Independent System Operator	No	R7 is unnecessary as the applicability section of the standard is clear that the standard applies to those circuits identified in R6. This requirement could be construed as potential for double jeopardy because failure to comply with Requirements 1-5 represents a violation of both Requirement 7 and Requirements 1-5.
Response: Thank you for your comment. The drafting team understands the double jeopardy concern and has deleted Requirement R7. The Effective Dates section has been modified to address the timeframe in which Facility owners must comply with Requirements R1 through R5 when the Planning Coordinator identifies a circuit for which the Facility owner must comply with the standard.		
Oncor Electric Delivery Company LLC	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
Ameren	No	As this requirement is structured, it creates a potential for double jeopardy should one of the other requirements mentioned (R1 through R5) be violated. This requirement is not needed and should be removed from the proposed standard.
Response: Thank you for your comment. The drafting team understands the double jeopardy concern and has deleted Requirement R7. The Effective Dates section has been modified to address the timeframe in which Facility owners must comply with Requirements R1 through R5 when the Planning Coordinator identifies a circuit for which the Facility owner must comply with the standard.		
National Grid	Yes	

Organization	Yes or No	Question 6 Comment
ERCOT ISO	Yes	
MidAmerican Energy	No	We do not believe that R7 is needed. The applicability section of the standard is clear that the standard applies to those circuits identified in R6. This requirement could be construed as potential for double jeopardy because failure to comply with Requirements 1-5 for represent a violation of both Requirement 7 and Requirement 1-5.
Response: Thank you for your comment. The drafting team understands the double jeopardy concern and has deleted Requirement R7. The Effective Dates section has been modified to address the timeframe in which Facility owners must comply with Requirements R1 through R5 when the Planning Coordinator identifies a circuit for which the Facility owner must comply with the standard.		
Xcel Energy	Yes	

7. *PRC-023 - Attachment A, section 1.6 has been revised to avoid unintended negative impact on reliability associated with referring to "Protective functions that supervise operation of other protective functions." Section 1.6 has been revised to "Supervisory elements associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications" to be more specific to the concern stated in Order No. 733. Do you agree that this is an equally efficient and effective method of meeting this directive? If not, please explain and provide specific suggestions for improvement.*

Summary Consideration: In response to Question 7, most stakeholders who responded to the question indicated support for Section 1.6.

Several commenters questioned the applicability of this requirement only to current-based telecommunication schemes to which the drafting team responded "Current-differential telecommunications systems are different than other telecommunications systems, in that the sensitivities for the protection elements are often set very sensitively – well below load current – and depend on the integrity of the channel to make a trip/no trip decision where other telecommunication system technologies require the operation of other protection system elements (usually distance elements) which are already subject to the requirements of this standard. Therefore, they will trip immediately due to load current upon the loss of communications, and are dependent on the fault detectors to inhibit trip which must therefore be secure regardless of how infrequently loss of communications may occur".

There are also comments addressing supervisory elements vs. loss of potential to which the drafting team responded "For a loss-of-potential, there will often be indications that the condition exists, allowing rapid response for repair."

Organization	Yes or No	Question 7 Comment
Electric Market Policy	Yes	
Potomac Holdings Inc & Affiliates	No	The current wording of section 1.6 is a significant improvement over the previous version. The intent of this section was to specifically address phase overcurrent supervising elements (i.e. phase fault detectors) associated with pilot wire, phase comparison, and line current differential schemes where the scheme is capable of tripping for loss of communications. However, we believe that the term "current-based communication-assisted schemes" is too generic and may be confusing without mention of the specific schemes to which this requirement applies. Also, only phase overcurrent supervising elements are in scope, not ground overcurrent supervising elements. Therefore, to clarify the requirement we suggest replacing the current wording with either "Phase overcurrent supervisory elements (i.e. phase fault detectors) associated with pilot wire, phase

Organization	Yes or No	Question 7 Comment
		comparison, and line current differential schemes, where the scheme is capable of tripping for loss of communications” or “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”.
Response: Thank you for your comment. Attachment A applies to the listed protective functions that respond to load so it’s unnecessary to use the word “phase”. Section 1.6 has otherwise been modified essentially as you suggest in response to your comment.		
Northeast Power Coordinating Council	Yes	
Pacific Northwest Small Public Power Utility Comment Group	Yes	
Tri-State G & T System Protection	Yes	
Midwest ISO Standards Collaborators	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
Santee Cooper	Yes	
Bonneville Power Administration	Yes	
FirstEnergy	Yes	
IRC Standards Review Committee	Yes	
Tennessee Valley Authority	Yes	

Organization	Yes or No	Question 7 Comment
New York Power Authority	Yes	
Manitoba Hydro	No	Effectively, there is no substantial difference between the protection elements described in section 1.6 and the protection elements described on second bullet in Section 2.1. Why should the protection elements in section 1.6 be included? During loss of communication, the supervisory elements associated with current based, communication-assisted schemes (such as line current differential scheme and phase comparison scheme) may be the only protection elements to provide high speed protection which may be necessary from system reliability perspective. As a result, these supervisory elements should be set low enough to ensure that they can detect all fault condition. Since these supervisory elements are only in effect under loss of communication contingency, I don't think they should be subjected to the same requirements as those load responsive elements under normal condition. They should be treated the same as those elements described on the first bullet in section 2.1.
Response: Thank you for your comment. Current-differential telecommunications systems are different than other telecommunications systems, in that the sensitivities for the protection elements are often set very sensitively – well below load current – and depend on the integrity of the channel to make a trip/no trip decision where other telecommunication system technologies require the operation of other protection system elements (usually distance elements) which are already subject to the requirements of this standard. Therefore, they will trip immediately due to load current upon the loss of communications, and are dependent on the fault detectors to inhibit trip which must therefore be secure regardless of how infrequently loss of communications may occur. For a loss-of-potential, there will often be indications that the condition exists, allowing rapid response for repair.		
Lakeland Electric	Yes	
NIPSCO	No	Don't know what is referred to here except maybe a current differential scheme. There is no need for this added requirement.
Response: Thank you for your comment. Current-differential telecommunications systems are different than other telecommunications systems, in that the sensitivities for the protection elements are often set very sensitively – well below load current – and depend on the integrity of the channel to make a trip/no trip decision where other telecommunication system technologies require the operation of other protection system elements (usually distance elements) which are already subject to the requirements of this standard. Therefore, they will trip immediately due to load current upon the loss of communications, and are dependent on the fault detectors to inhibit trip which must therefore be secure regardless of how infrequently loss of communications may occur.		

Organization	Yes or No	Question 7 Comment
Western Area Power Administration	No	Both the FERC order and section 1.6 are unclear.
Response: Thank you for your comment. Absent the specific comment, the drafting team is unable to respond. In response to other comments, the drafting team has modified Section 1.6 to provide additional clarity.		
Minnkota Power Cooperative, Inc.	Yes	
Duke Energy	Yes	
Kansas City Power & Light	Yes	
American Transmission Company	Yes	
Orange and Rockland Utilities, Inc.	Yes	
City of Jacksonville Beach, FL dba/Beaches Energy Services	Yes	
American Electric Power	No	The wording of Attachment A, section 1.6 needs to be made consistent to avoid any confusion.1.6 Reword to read: "Supervisory elements used as fault detectors associated with pilot wire or current differential protection systems where the system is capable of tripping for loss of communications".
Response: Thank you for your comment. Section 1.6 has been modified essentially as is suggested in the comment.		
Nebraska Public Power District	Yes	
Great River Energy	Yes	

Organization	Yes or No	Question 7 Comment
Northeast Utilities	Yes	
New York Independent System Operator	Yes	
Oncor Electric Delivery Company LLC	Yes	
Consolidated Edison Co. of NY, Inc.	Yes	
Ameren	No	Section 1.6 is contrary to section 2.0 and seems arbitrary. Why is a communication system for a current-based scheme treated to a higher standard than other communications scheme? The communications scheme reliability is covered through the maintenance and misoperations analysis standards.
Response: Thank you for your comment. Current-differential telecommunications systems are different than other telecommunications systems, in that the sensitivities for the protection elements are often set very sensitively – well below load current – and depend on the integrity of the channel to make a trip/no trip decision where other telecommunication system technologies require the operation of other protection system elements (usually distance elements) which are already subject to the requirements of this standard. Therefore, they will trip immediately due to load current upon the loss of communications, and are dependent on the fault detectors to inhibit trip.		
National Grid	Yes	
ERCOT ISO	Yes	
MidAmerican Energy	Yes	
Xcel Energy	Yes	

8. *Attachment B contains the test that the Planning Coordinators must use to determine which transmission elements (transmission lines operated below 200 kV and transformers with low voltage terminals connected below 200 kV) must comply with this standard. Do you agree that the method proposed in Attachment B is a technically sound approach? If not, please explain and provide specific suggestions for improvement.*

Summary Consideration: In response to Question 8, most stakeholders who responded to this question indicated disagreement with the method proposed in Attachment B.

The drafting team received several comments regarding "going beyond" TPL requirements by not simulating manual system adjustment in between contingencies in Attachment B, criterion B4. The purpose of this criterion is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. As such, criterion B4 does not require that all double contingency combinations be tested. It also does not require that the loadings respect the published applicable ratings of the circuits. It does require that engineering judgment be used to select certain combinations of line outages to be studied without manual system adjustment to ensure that, if the manual adjustments were not completed before the second contingency, the relay settings on the lines remaining in service would not inappropriately trip the lines.

The drafting team has modified criterion B5 in response to industry comments to require that if the Planning Coordinator selects a circuit based on technical studies or assessments, other than those specified in criteria B1 through B4, that such selection shall be made in consultation with the Facility owner to provide the Facility owner an opportunity for input into the assessment. Additionally, an appeals process will be included in the NERC Rules of Procedure so that a Facility owner may appeal a decision in the event it believes a circuit is incorrectly identified by the Planning Coordinator.

Commenters expressed concern that the proposed implementation plan for PRC-023-2 has the unintended consequence of shortening the time provided for Facility owners to comply with Requirement R1 for switch-on-to-fault schemes. The drafting team has modified the effective dates in the standard to address this problem

Commenters indicated clarification was needed to identify which Interconnection Reliability Operating Limits (IROLs) are to be considered in application of Attachment B, criterion B2. Also, there was some confusion as to the requirements of the standard, since the long term planning horizon may include transmission projects that have not been built or alternative system configurations that do not exist, making it impossible for affected parties to set their relays appropriately. In response to several comments on this subject, the drafting team has replaced the reference to "determined in the long-term planning horizon" with "determined in the planning horizon pursuant to FAC-010."

In response to comments on criterion B3, the drafting team has modified the criterion to refer explicitly to "the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001." The drafting team believes this modification to criterion B3 provides a level of measurability that should address the commenters' concerns.

Many commenters expressed their belief that flowgates are market-based tools that are not appropriate for use in assessing system reliability. The drafting team responded that congestion and system reliability are not mutually exclusive concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. While flowgates are used to manage congestion, the underlying basis for doing so is to preserve system reliability. As such, it is appropriate and necessary to include monitored Facilities of flowgates as applicable circuits under PRC-023-2.

Based on a number of comments, the drafting team has modified Attachment B, criterion B1 to refer to "permanent" flowgates and has replaced the reference to "long-term reliability concerns" with "reliability concerns for loading of that circuit." The drafting team believes this more clearly reflects the intent to exclude flowgates that are established on a temporary basis and more clearly identifies the role of the Planning Coordinator in applying criterion B1.

Organization	Yes or No	Question 8 Comment
Electric Market Policy		5.1 Requirement R1. Dominion would like to see the exception of "switch on to fault" schemes added back in.
Response: Thank you for your comment. The drafting team understands the commenter's concern that the proposed implementation plan for PRC-023-2 had the unintended consequence of shortening the time provided for Facility owners to comply with Requirement R1 for switch-on-to-fault schemes. The drafting team has modified the effective dates in the standard to address this problem.		
Potomac Holdings Inc & Affiliates	Yes	
Northeast Power Coordinating Council	No	1) B2. Item B2 adds significant confusion to the process. The long term planning horizon may include transmission projects which have not even been built or alternative system configurations which do not exist, making it impossible for affected parties to set their relays appropriately. Suggested replacement language to avoid this issue: "Each circuit that is a monitored element of an IROL, assuming that all transmission elements are in service and the system is under normal conditions." 2) B3. This item indicates that the circuits to be considered are to be agreed to by the plant owner and the Transmission Entity. Attachment B is applicable to the Planning Coordinator. If this item is by agreement by the plant and the Transmission Entity it should be removed from Attachment B and placed elsewhere in the document. If this is intended to apply to the Planning Coordinator, Transmission Entity should be replaced with Planning Coordinator. Why does B3 only apply to Nuclear Power Plants? 3) B4. This criterion is overly stringent and should be deleted. The system is neither planned nor operated to allow for two overlapping outages without operator action in between. If this criterion is retained, it

Organization	Yes or No	Question 8 Comment
		should be made consistent with the requirements of TPL-003 where operator actions can be assumed between the first and second contingencies. Since a similar comment was made previously, more information is being provided following.1. Since the system is neither planned nor operated to two overlapping outages in between, such testing may result in unsolved cases, or voltages well below criteria. In the case of an unsolved case, there are no flows to evaluate, making this standard impossible to apply. In the case of a solved case with voltages well below criteria, currents are likely to be incredibly high and therefore viewed as unrealistic. These concerns may limit the contingency selection to those which are not severe, eliminating any perceived benefit from this testing.2. There is no guidance provided on how the system should be dispatched in the model upon which the overlapping contingencies are tested. This will result in significant discrepancies between the base assumptions used by the various Planning Coordinators. The contents of this standard should be reviewed to reflect the new definition of the Bulk Electric System.
Response: Thank you for your comment. 1) In response to several comments on this subject the drafting team has replaced the reference to “determined in the long-term planning horizon” with “determined in the planning horizon pursuant to FAC-010.” 2) T his criterion applies to the Planning Coordinator and requires that the Planning Coordinator include circuits that form a path “(as agreed to by the plant owner 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” on the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2. This criterion applies specifically to nuclear plants for the purpose of supporting nuclear plant safe operation and shutdown. The drafting team believes the added reference to the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001 better reflects this intent. 3) The drafting team received several comments regarding “going beyond” TPL requirements by not simulating manual system adjustment in between contingencies. The purpose of this criterion is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. As such, criterion B4 does not require that all double contingency combinations be tested. It also does not require that the loadings respect the published applicable ratings of the circuits. It does require that engineering judgment be used to select certain combinations of line outages to be studied without manual system adjustment to ensure that, if the manual adjustments were not completed before the second contingency, the relay settings on the lines remaining in service would not inappropriately trip the lines.		
Pacific Northwest Small Public Power Utility Comment Group	No	We thank the SDT for addressing our concern regarding radially operated circuits. We note, however, that the key word “operated” from the consideration of comments was dropped before it reached the standard. Please change the last bullet of B4 to:"Radially operated circuits serving only load are excluded."
Response: Thank you for your comment.		

Organization	Yes or No	Question 8 Comment
The drafting team agrees with your comment and has modified criterion B4 accordingly.		
Tri-State G & T System Protection	Yes	1) While we agree that it is a technically sound approach, we have concerns that the criterion B4 is over-burdensome. Paragraph 82 of FERC Order 733 indicates that the existing TPL simulations and assessments should be a component of the test. By excluding manual intervention in the assessments the Attachment is expanding the scope beyond the Commission's Order. We think there should be a test based on the existing assessments required by the TPL standards that would then trigger a subsequent test with no manual intervention. An example would be if an element's loading exceeded 100% of its Facility Rating using the normal assessment, then the assessment with no manual intervention would be applied and subsequent steps of criterion B4 would be followed. 2) We think that criterion B5 is too vague, may be discriminatory, is unnecessary, and should be removed. There is very little basis listed for this criterion above and beyond those listed in criterion B4, the criterion may be applied discriminatorily or differently even within the same interconnection, it potentially excludes the protection system owner from having input in the process, and there is no redress for appeal by the owner. It seems highly unlikely that elements that are not identified through criterion B4 will need to be included. If some form of criterion B5 is included in Attachment B, then it needs to better define a technical basis for the request for inclusion, a procedure to initiate the request for inclusion, due process defined for evaluation of the request, and inclusion of the protection system owner in the evaluation process and the agreement.
Response: Thank you for your comment. 1) The drafting team received several comments regarding "going beyond" TPL requirements by not simulating manual system adjustment in between contingencies. The purpose of this criterion is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. As such, criterion B4 does not require that all double contingency combinations be tested. It also does not require that the loadings respect the published applicable ratings of the circuits. It does require that engineering judgment be used to select certain combinations of line outages to be studied without manual system adjustment to ensure that, if the manual adjustments were not completed before the second contingency, the relay settings on the lines remaining in service would not inappropriately trip the lines. 2) The drafting team has modified criterion B5 in response to industry comments to require that if the Planning Coordinator selects a circuit based on technical studies or assessments, other than those specified in criteria B1 through B4, that such selection is to be made in consultation with the Facility owner to provide the Facility owner an opportunity for input into the assessment. Additionally, an appeals process will be included in the NERC Rules of Procedure so that a Facility owner may appeal a decision in the event it believes a circuit is incorrectly identified by the Planning Coordinator.		
Midwest ISO Standards Collaborators	No	1) While we appreciate the drafting team's effort to refine the flowgate criteria from the last posting, the modifications do not go far enough and still do not reflect the use of flowgates. NERC's definition of

Organization	Yes or No	Question 8 Comment
		flowgate includes two components. Let's focus on the first component which represents those flowgates defined in the IDC. Because IDC flowgates list is updated monthly and the IDC users can add temporary flowgates to the IDC at any time, this is an inappropriate list to use. We appreciate the drafting team's attempt to resolve this issue by including the caveat "that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator." However, this really only confuses the matter and does not solve it. Reliability Coordinators add flowgates to manage real-time congestion. Planning Coordinators do not. Per the NERC functional model, they do not even have a role in deciding which flowgates to add to the IDC. Flowgates are added to the IDC to mitigate existing, known congestion points not congestion points identified in a long-term planning study that may never materialize due to changing conditions. Thus, IDC flowgates should be specifically excluded.Now let us focus on the second component of flowgate. The second component is much like the first component in that is it a mathematical construct to analyze the impact of power flows on the BES except is not required to be included in the IDC. There is nothing in the definition of a flowgate to give credence that is represents anything more than point to calculate power flows and the impact of transactions. Flowgates are primarily used to manage congestion on the system and to sell transmission system. Because it is convenient to select a group of lines as a proxy to sell transmission service or manage congestion does not mean that those group of lines represent a reliability issue. Thus, we do not believe any flowgates should be included in the list. Any true reliability issues can be identified through the TPL studies and those facilities that do not meet the performance requirements are what should be used. 2) We do not support criterion B4. It exceeds what is required in the TPL standards and what is required per the reliability directive in Order 729. The TPL standards allow system operator intervention for category C3 contingencies between the two independent Category B contingencies. This standard should not exceed those requirements in the TPL standards. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test "must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning." Paragraph 80 states that "the test must be consistent with the general reliability principles embedded in the existing series of TPL" standards. Thus, exceeding the TPL standards could be argued as deviating from the directive. In response to comments that did not support this criterion during the first posting, the standards drafting team responded with "Testing multiple element contingencies while accounting for system adjustments between each element outage will not yield any facilities to be subject to PRC-023 as long as TPL-003 system performance requirements are met." We think the drafting team missed a basic point about the standard. The issue is not whether the registered entity develops and documents corrective action plans TPL-003-0a R2 and R3. The issue is if the system as currently designed meets the performance requirements in TPL-003-0a R1 which allows for operator interventions on Category C3 contingencies. For those C3 contingencies that don't currently meet the performance obligations after operator interventions, the subject facilities would be included PRC-023-2

Organization	Yes or No	Question 8 Comment
		R6 list of facilities.

Response: Thank you for your comment.

1) Congestion and system reliability are not mutually exclusive concerns. The Interchange Distribution Calculator (IDC) was developed to address reliability concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. The IDC is intended to identify and unload critical circuits that could become overloaded due to transactions. While Flowgates and the IDC are used to manage congestion, the underlying basis for doing so is to preserve system reliability.

   The Flowgate Methodology defines that Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. If monitored Facilities of flowgates do not meet the Relay Loadability requirements in PRC-023, violation of physical system limitations could occur, leading to instability, uncontrolled separation, or cascading outages. As such, it is appropriate and necessary to include monitored Facilities of flowgates as applicable circuits under PRC-023-2.

   The drafting team acknowledges that Planning Coordinators do not decide which flowgates are included in the IDC; however, the NERC Functional Model does indicate that Planning Coordinators are responsible for coordinating transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators. Thus it is appropriate that Planning Coordinators, in applying the criteria in Appendix B, provide a screening as to whether the monitored Facilities of a flowgate are added to the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2.

   Based on a number of comments, the drafting team has modified criterion B1 to refer to “permanent” flowgates and has replaced the reference to “long-term reliability concerns” with “reliability concerns for loading of that circuit.” The drafting team believes this more clearly reflects the intent to exclude flowgates that are established on a temporary basis and more clearly identifies the role of the Planning Coordinator in applying criterion B1.

2) The drafting team received several comments regarding “going beyond” TPL requirements by not simulating manual system adjustment in between contingencies. The purpose of this criterion is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. As such, criterion B4 does not require that all double contingency combinations be tested. It also does not require that the loadings respect the published applicable ratings of the circuits. It does require that engineering judgment be used to select certain combinations of line outages to be studied without manual system adjustment to ensure that, if the manual adjustments were not completed before the second contingency, the relay settings on the lines remaining in service would not inappropriately trip the lines.

Organization	Yes or No	Question 8 Comment
MRO's NERC Standards Review Subcommittee	No	1) While we appreciate the drafting team’s effort to refine the flowgate criteria from the last posting, the modifications do not go far enough and still do not reflect the use of flowgates. NERC’s definition of flowgate includes two components. Let’s focus on the first component which represents those flowgates defined in the IDC. Because IDC flowgates list is updated monthly and the IDC users can add temporary flowgates to the IDC at any time, this is an inappropriate list to use. We appreciate the drafting team’s attempt to resolve this issue by including the caveat “that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator.” However, this really only

Organization	Yes or No	Question 8 Comment
		confuses the matter and does not solve it. Reliability Coordinators add flowgates to manage real-time congestion. Planning Coordinators do not. Per the NERC functional model, they do not even have a role in deciding which flowgates to add to the IDC. Flowgates are added to the IDC to mitigate existing, known congestion points not congestion points identified in a long-term planning study that may never materialize due to changing conditions. Thus, IDC flowgates should be specifically excluded. Now let us focus on the second component of flowgate. The second component is much like the first component in that is it a mathematical construct to analyze the impact of power flows on the BES except is not required to be included in the IDC. There is nothing in the definition of a flowgate to give credence that is represents anything more that point to calculate power flows and the impact of transactions. Flowgates are primarily used to manage congestion on the system and to sell transmission system. Because it is convenient to select a group of lines as a proxy to sell transmission service or manage congestion does not mean that those group of lines represent a reliability issue. Thus, we do not believe any flowgates should be included in the list. Any true reliability issues can be identified through the TPL studies and those facilities that do not meet the performance requirements are what should be used. 2) We do not support criterion B4. It exceeds what is required in the TPL standards and what is required per the reliability directive in Order 729. The TPL standards allow system operator intervention for category C3 contingencies between the two independent Category B contingencies. This standard should not exceed those requirements in the TPL standards. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test “must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning.” Paragraph 80 states that “the test must be consistent with the general reliability principles embedded in the existing series of TPL” standards. Thus, exceeding the TPL standards could be argued as deviating from the directive. In response to comments that did not support this criterion during the first posting, the standards drafting team responded with “Testing multiple element contingencies while accounting for system adjustments between each element outage will not yield any facilities to be subject to PRC-023 as long as TPL-003 system performance requirements are met.” We think the drafting team missed a basic point about the standard. The issue is not whether the registered entity develops and documents corrective actions plans per TPL-003-0a R2 and R3. The issue is if the system as currently designed meets the performance requirements in TPL-003-0a R1 which allows for operator interventions on Category C3 contingencies. For those C3 contingencies that don’t currently meet the performance obligations after operator interventions, the subject facilities would be included PRC-023-2 R6 list of facilities.

Response: Thank you for your comment.

1) Congestion and system reliability are not mutually exclusive concerns. The Interchange Distribution Calculator (IDC) was developed to address reliability

Organization	Yes or No	Question 8 Comment
concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. The IDC is intended to identify and unload critical circuits that could become overloaded due to transactions. While Flowgates and the IDC are used to manage congestion, the underlying basis for doing so is to preserve system reliability. The Flowgate Methodology defines that Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. If monitored Facilities of flowgates do not meet the Relay Loadability requirements in PRC-023, violation of physical system limitations could occur, leading to instability, uncontrolled separation, or cascading outages. As such, it is appropriate and necessary to include monitored Facilities of flowgates as applicable circuits under PRC-023-2. The drafting team acknowledges that Planning Coordinators do not decide which flowgates are included in the IDC; however, the NERC Functional Model does indicate that Planning Coordinators are responsible for coordinating transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators. Thus it is appropriate that Planning Coordinators, in applying the criteria in Appendix B, provide a screening as to whether the monitored Facilities of a flowgate are added to the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2. Based on a number of comments, the drafting team has modified criterion B1 to refer to "permanent" flowgates and has replaced the reference to "long-term reliability concerns" with "reliability concerns for loading of that circuit." The drafting team believes this more clearly reflects the intent to exclude flowgates that are established on a temporary basis and more clearly identifies the role of the Planning Coordinator in applying criterion B1. 2) The drafting team received several comments regarding "going beyond" TPL requirements by not simulating manual system adjustment in between contingencies. The purpose of this criterion is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. As such, criterion B4 does not require that all double contingency combinations be tested. It also does not require that the loadings respect the published applicable ratings of the circuits. It does require that engineering judgment be used to select certain combinations of line outages to be studied without manual system adjustment to ensure that, if the manual adjustments were not completed before the second contingency, the relay settings on the lines remaining in service would not inappropriately trip the lines.		
Santee Cooper	No	The criteria in Attachment B lack clarity. 1) For example, B4 criterion for powerflow analysis does not specify a horizon. 2) In addition, in B1 does that only apply to circuits that are monitored by you or the IDC? 3) Assessing the post-contingency loading and determining if a facility rating is based on loading durations of specified time periods is too burdensome and would not provide much value.
Response: Thank you for your comment. 1) The drafting team has modified criterion B4 to specify that the powerflow analysis is to be performed for the one-to-five-year planning horizon. 2) Criterion B1 applies to circuits monitored by the IDC.		

Organization	Yes or No	Question 8 Comment
3) The purpose of the loadability standard is to ensure that protective relays are set to detect fault conditions but will not interfere with the system operators' ability to take remedial action to protect system reliability. Simulations must be performed to assess the susceptibility to cascading outages to determine what protective relays must be set in accordance with the relay loadability requirements.		
Bonneville Power Administration	No	The evaluation method seems technically sound. The second category of applicable circuits, "Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV ...", are not considered BES elements based on the latest definition and BPA does not believe that this category of circuits should be included.
Response: Thank you for your comment. The drafting team understands the concern with including facilities operated below 100 kV; however, the NERC Statement of Compliance Registry Criteria does allow Regional Entities the ability to identify such facilities operated below 100 kV as required to comply with NERC Reliability Standards. The drafting team has replaced the phrase "critical for the purposes of the Compliance Registry" with text from ¶60 of Order No. 733, which references text in section III.d.2 of the NERC Statement of Compliance Registry Criteria. So the second category of circuits to be evaluated now refers to transmission lines and transformers operated below 100 kV "that are included on a critical facilities list defined by the Regional Entity."		
FirstEnergy	No	FE proposes that criterion B1 be removed from Attachment B. We support criterion B3 as written and proposed revised versions of criterion B2 and B4. 1) a. Item B1 implies all facilities operated below 200kV and associated with a Flowgate must comply with the PRC-023 standard. We support both MISO's and PJM's view that this criterion should be removed since Flowgates in their truest sense is used for economic and market transmission needs over reliability needs. Flowgates describe a designated point on the transmission system through which the Interchange Distribution Calculator (IDC) calculates the power flow from Interchange Transactions. While its recognized the drafting team attempted improve the Flowgate criteria by including a statement "that has been included to address a long-term reliability concerns, as confirmed by the applicable Planning Coordinator", it is FE's opinion that a Planning Coordinator does not play a role in adding or revising Flowgates used in the IDC and do not utilize Flowgates for long-term reliability planning purposes. Flowgates are a means of managing congestion and for identifying available transfer capability. Continued use of this criterion will only serve to confuse and complicate matters. 2) b. Item B2 should be revised to include not only the monitored facilities associated with the IROL, but also any "contingent" facilities that may describe the IROL condition. For example, it is important to include the transmission facilities described in a NERC C3 contingency that may be associated with an IROL definition. A C3 contingency describes a N-1-1 condition with system adjustments permitted in between the 1st and 2nd contingency. It is necessary to ensure that the 2nd contingent facility does not prematurely trip due to a relay loadability limitation. For greater consistency with terminology used in the

Organization	Yes or No	Question 8 Comment
		FAC-014 standard, Requirement R5.1 we propose the following for criterion B2: "B2. Each circuit monitored as critical to the derivation of an IROL and each circuit associated with the Contingency(ies) that describe the need for the IROL." 3) c. We support criterion B3 as written. 4) d. In regards to criterion B4, FE supports the team's recommendation for the Planning Coordinator to perform a modified NERC Category C3 analysis to further identify sub 200kV facilities applicable to the PRC-023 standard. However, the sub-bullets identifying various loading thresholds depending on the Facility rating is overly complicated and creates undue burden for the Planning Coordinator performing the study. We propose that the team simplify this criterion to clarify the applicable facilities are those that exceed 130% of their continuous emergency rating for the modified NERC Category C3 test.

Response: Thank you for your comment.

1) Congestion and system reliability are not mutually exclusive concerns. The Interchange Distribution Calculator (IDC) was developed to address reliability concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. The IDC is intended to identify and unload critical circuits that could become overloaded due to transactions. While Flowgates and the IDC are used to manage congestion, the underlying basis for doing so is to preserve system reliability.

   The Flowgate Methodology defines that Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. If monitored Facilities of flowgates do not meet the Relay Loadability requirements in PRC-023, violation of physical system limitations could occur, leading to instability, uncontrolled separation, or cascading outages. As such, it is appropriate and necessary to include monitored Facilities of flowgates as applicable circuits under PRC-023-2.

   The drafting team acknowledges that Planning Coordinators do not decide which flowgates are included in the IDC; however, the NERC Functional Model does indicate that Planning Coordinators are responsible for coordinating transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators. Thus it is appropriate that Planning Coordinators, in applying the criteria in Appendix B, provide a screening as to whether the monitored Facilities of a flowgate are added to the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2.

   Based on a number of comments, the drafting team has modified criterion B1 to refer to "permanent" flowgates and has replaced the reference to "long-term reliability concerns" with "reliability concerns for loading of that circuit." The drafting team believes this more clearly reflects the intent to exclude flowgates that are established on a temporary basis and more clearly identifies the role of the Planning Coordinator in applying criterion B1.

2) The drafting team appreciates this suggestion, but believes that the circuits identified through criterion B2 should be the monitored Facilities that comprise an IROL; if a contingent Facility could have an impact on the BES the circuit would be included as a monitored Facility or identified through another criterion in Attachment B.

3) Thank you for your support.

Organization	Yes or No	Question 8 Comment
4) The drafting team proposed multiple thresholds to account for the thermal characteristics of equipment and variations in Facility Rating methodologies to avoid an overly conservative, one-size-fits-all approach. Based on industry feedback, the drafting team has elected not to prescribe a single threshold value, but to allow the flexibility as provided in the existing draft attachment.		
IRC Standards Review Committee	No	1) We disagree with B1 which includes monitored elements of flowgates. Flowgates may not always be used for reliability purposes and may be temporary to address certain economic conditions. While we appreciate the drafting team's effort to refine the flowgate criteria from the last posting, the modifications do not go far enough and still do not reflect the use of flowgates. NERC's definition of flowgate includes two components. Let's focus on the first component which represents those flowgates defined in the IDC. Because IDC flowgates list is updated monthly and the IDC users can add temporary flowgates to the IDC at any time, this is an inappropriate list to use. We appreciate the drafting team's attempt to resolve this issue by including the caveat "that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator." However, this really only confuses the matter and does not solve it. Reliability Coordinators add flowgates to manage real-time congestion. Planning Coordinators do not. Per the NERC functional model, they do not even have a role in deciding which flowgates to add to the IDC. Flowgates are added to the IDC to mitigate existing, known congestion points not congestion points identified in a long-term planning study that may never materialize due to changing conditions. Thus, IDC flowgates should be specifically excluded. Now let us focus on the second component of flowgate. The second component is much like the first component in that is it a mathematical construct to analyze the impact of power flows on the BES except is not required to be included in the IDC. There is nothing in the definition of a flowgate to give credence that is represents anything more that point to calculate power flows and the impact of transactions. Flowgates are primarily used to manage congestion on the system and to sell transmission system. Because it is convenient to select a group of lines as a proxy to sell transmission service or manage congestion does not mean that those group of lines represent a reliability issue. Thus, we do not believe any flowgates should be included in the list. Any true reliability issues can be identified through the TPL studies and those facilities that do not meet the performance requirements are what should be used. 2) We do not support criterion B4. It exceeds what is required in the TPL standards and what is required per the reliability directive in Order 729. The TPL standards allow system operator intervention for category C3 contingencies between the two independent Category B contingencies. This standard should not exceed those requirements in the TPL standards. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test "must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning." Paragraph 80 states that "the test must be consistent with the general reliability principles embedded in the existing series of TPL" standards. Thus, exceeding the TPL standards could be argued as deviating from the directive. The directive is to be consistent not exceed. Exceeding the

Organization	Yes or No	Question 8 Comment
		TPL standards is not consistency. In response to comments that did not support this criterion during the first posting, the standards drafting team responded with "Testing multiple element contingencies while accounting for system adjustments between each element outage will not yield any facilities to be subject to PRC-023 as long as TPL-003 system performance requirements are met." We think the drafting team missed a basic point about the standard. The issue is not whether the registered entity develops and documents corrective action plans TPL-003-0a R2 and R3. The issue is if the system as currently designed meets the performance requirements in TPL-003-0a R1 which allows for operator interventions on Category C3 contingencies. For those C3 contingencies that don't currently meet the performance obligations after operator interventions, the subject facilities would be included PRC-023-2 R6 list of facilities. Note: CAISO does not sign on to the above comments.

Response: Thank you for your comment.

1) Congestion and system reliability are not mutually exclusive concerns. The Interchange Distribution Calculator (IDC) was developed to address reliability concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. The IDC is intended to identify and unload critical circuits that could become overloaded due to transactions. While Flowgates and the IDC are used to manage congestion, the underlying basis for doing so is to preserve system reliability.

   The Flowgate Methodology defines that Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. If monitored Facilities of flowgates do not meet the Relay Loadability requirements in PRC-023, violation of physical system limitations could occur, leading to instability, uncontrolled separation, or cascading outages. As such, it is appropriate and necessary to include monitored Facilities of flowgates as applicable circuits under PRC-023-2.

   The drafting team acknowledges that Planning Coordinators do not decide which flowgates are included in the IDC; however, the NERC Functional Model does indicate that Planning Coordinators are responsible for coordinating transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators. Thus it is appropriate that Planning Coordinators, in applying the criteria in Appendix B, provide a screening as to whether the monitored Facilities of a flowgate are added to the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2.

   Based on a number of comments, the drafting team has modified criterion B1 to refer to "permanent" flowgates and has replaced the reference to "long-term reliability concerns" with "reliability concerns for loading of that circuit." The drafting team believes this more clearly reflects the intent to exclude flowgates that are established on a temporary basis and more clearly identifies the role of the Planning Coordinator in applying criterion B1.

2) The drafting team received several comments regarding "going beyond" TPL requirements by not simulating manual system adjustment in between contingencies. The purpose of this criterion is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. As such, criterion B4 does not require that all double contingency combinations be tested. It also does not require that the loadings respect the published applicable ratings of the circuits. It does require that engineering judgment be used to select certain combinations of line outages to be studied without manual system adjustment to ensure that, if the manual adjustments were not completed before the second contingency, the relay settings on the

Organization	Yes or No	Question 8 Comment
lines remaining in service would not inappropriately trip the lines.		
Tennessee Valley Authority	No	The NERC Glossary defines a flowgate as:1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System. The IDC flowgates change often thus making it difficult to coordinate those changes with the critical lines list provided by the Planning Coordinator in Attachment B section B1. We assume that No. 2 above is the definition that the SDT was referring. However, for clarity, we recommend that either the word "flowgate" be specifically defined in Attachment B or removed.
Response: Thank you for your comment. Congestion and system reliability are not mutually exclusive concerns. The Interchange Distribution Calculator (IDC) was developed to address reliability concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. The IDC is intended to identify and unload critical circuits that could become overloaded due to transactions. While Flowgates and the IDC are used to manage congestion, the underlying basis for doing so is to preserve system reliability. The Flowgate Methodology defines that Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. If monitored Facilities of flowgates do not meet the Relay Loadability requirements in PRC-023, violation of physical system limitations could occur, leading to instability, uncontrolled separation, or cascading outages. As such, it is appropriate and necessary to include monitored Facilities of flowgates as applicable circuits under PRC-023-2. The drafting team acknowledges that Planning Coordinators do not decide which flowgates are included in the IDC; however, the NERC Functional Model does indicate that Planning Coordinators are responsible for coordinating transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators. Thus it is appropriate that Planning Coordinators, in applying the criteria in Appendix B, provide a screening as to whether the monitored Facilities of a flowgate are added to the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2. Based on a number of comments, the drafting team has modified criterion B1 to refer to "permanent" flowgates and has replaced the reference to "long-term reliability concerns" with "reliability concerns for loading of that circuit." The drafting team believes this more clearly reflects the intent to exclude flowgates that are established on a temporary basis and more clearly identifies the role of the Planning Coordinator in applying criterion B1.		
New York Power Authority	No	1) B2. Item B2 adds significant confusion to the process. The long term planning horizon may include transmission projects which have not even been built or alternative system configurations which do not exist, making it impossible for affected parties to set their relays appropriately. Suggested replacement language to avoid this issue: "Each circuit that is a monitored element of an IROL, assuming that all transmission elements are in service and the system is under normal conditions."

Organization	Yes or No	Question 8 Comment
		2) B3. This item indicates that the circuits to be considered are to be agreed to by the plant owner and the Transmission Entity. Attachment B is applicable to the Planning Coordinator. If this item is by agreement by the plant and the Transmission Entity it should be removed from Attachment B and placed elsewhere in the document. If this is intended to apply to the Planning Coordinator, Transmission Entity should be replaced with Planning Coordinator. Why does B3 only apply to Nuclear Power Plants? 3) B4. This criterion is overly stringent and should be deleted. The system is neither planned nor operated to allow for two overlapping outages without operator action in between. If this criterion is retained, it should be made consistent with the requirements of TPL-003 where operator actions can be assumed between the first and second contingencies. Since a similar comment was made previously, more information is being provided following.1. Since the system is neither planned nor operated to two overlapping outages in between, such testing may result in unsolved cases, or voltages well below criteria. In the case of an unsolved case, there are no flows to evaluate, making this standard impossible to apply. In the case of a solved case with voltages well below criteria, currents are likely to be incredibly high and therefore viewed as unrealistic. These concerns may limit the contingency selection to those which are not severe, eliminating any perceived benefit from this testing.2. There is no guidance provided on how the system should be dispatched in the model upon which the overlapping contingencies are tested. This will result in significant discrepancies between the base assumptions used by the various Planning Coordinators. The contents of this standard should be reviewed to reflect the new definition of the Bulk Electric System.

Response: Thank you for your comment.

1) In response to several comments on this subject the drafting team has replaced the reference to "determined in the long-term planning horizon" with "determined in the planning horizon pursuant to FAC-010."

2) This criterion applies to the Planning Coordinator and requires that the Planning Coordinator include circuits that form a path "(as agreed to by the plant owner 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" on the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2.

   This criterion applies specifically to nuclear plants for the purpose of supporting nuclear plant safe operation and shutdown. The drafting team believes the added reference to the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001 better reflects this intent.

3) The drafting team received several comments regarding "going beyond" TPL requirements by not simulating manual system adjustment in between contingencies. The purpose of this criterion is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. As such, criterion B4 does not require that all double contingency combinations be tested. It also does not require that the loadings respect the published applicable ratings of the circuits. It does require that engineering judgment be used to select certain combinations of line outages to be studied without manual system adjustment to ensure that, if the manual adjustments were not completed before the second contingency, the relay settings on the

Organization	Yes or No	Question 8 Comment
lines remaining in service would not inappropriately trip the lines.		
Manitoba Hydro	No	In Attachment B and the standard, there's discussion of 15 min., up to 4 hour, 4-8 hour and more than 8 hour ratings. This is very prescriptive and doesn't match the requirements in the Facility rating methodology standard or the model building limitations. It seems there is a disconnect between the FAC, TPL and PRC standards.
Response: Thank you for your comment. The drafting team proposed multiple thresholds to account for the thermal characteristics of equipment and variations in Facility Rating methodologies to avoid an overly conservative, one-size-fits-all approach. The drafting team does not believe that there is a conflict between Attachment B and the FAC and TPL standards. Rather, Attachment B recognizes differences in the rating methodologies developed pursuant to the FAC standards and their application in the TPL standards, and accommodates these differences.		
Lakeland Electric	Yes	
NIPSCO	Yes	1) The method seems OK but the standard requirement R1 should be changed because lower voltage lines have far more resistance and arc resistance needs to be included. 2) General Comments: We think that the proposed revised standard incorrectly assigns responsibility to the PC instead of the TO,GO DP 3) Also, the new standard forces compliance on lower voltage lines which would limit protection of equipment which will ultimately lead to many fewer networked lines and a less reliable electric system.
Response: Thank you for your comment. 1) The drafting team understands your concern and will place this item in the issues database for future consideration in the next general revision of the standard. 2) The Planning Coordinator is the NERC Functional Model entity with the wide-area view and study expertise necessary to perform the assessment in Attachment B. The drafting team also notes that assigning this responsibility to the Planning Coordinator is consistent with the approved PRC-023-1 and FERC Order No. 733. 3) Compliance with PRC-023-2 can be achieved without limiting protection of equipment or necessitating that networked lines be operated radially. The drafting team notes that PRC-023-1 already applies to lines operated at 100 kV to 200 kV and PRC-023-2 only provides a uniform method by which Planning Coordinators will identify circuits for which applicable entities must comply. Although PRC-023-2 does pertain to certain sub-100 kV circuits as directed in Order No. 733, the drafting team does not believe that a significant number of sub-100 kV circuits will be impacted.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 8 Comment</th></tr>
<tr><td>Western Area Power Administration</td><td>No</td><td>Is this necessary? Allow Planning Coordinators to do their jobs and decide which circuits are important.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

The drafting team believes it is important that all Planning Coordinators utilize a consistent methodology for identifying the Facilities below 200 kV for which the applicable entities must comply with PRC-023-2. FERC, in Order No. 733, identified concerns with lack of a consistent methodology and directed development of a consistent methodology for inclusion in PRC-023.</td></tr>
<tr><td>Minnkota Power Cooperative, Inc.</td><td>No</td><td>Many facilities with voltages between 100 kV and 200 kV will only impact a well-defined local load region if they trip. There is no risk of cascading outages beyond the local load region. The criteria in Attachment B should allow these facilities to be dismissed from further evaluation.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.

The criteria in Attachment B were selected to identify circuits that present a risk of cascading outages if relay loadability requirements are not met. The drafting team has added to some of the criteria that the Planning Coordinator shall consult with the Facility owner when performing its assessment to provide the Facility owner an opportunity for input into the assessment. Additionally, an appeals process will be included in the NERC Rules of Procedure so that a Facility owner may appeal a decision in the event it believes a circuit is incorrectly identified by the Planning Coordinator.</td></tr>
<tr><td>ISO New England Inc.</td><td>No</td><td>1) B2. Item B2 adds significant confusion to the process. The long term planning horizon may include transmission projects which have not even been built or alternative system configurations which do not exist, making it impossible for affected parties to set their relays appropriately. Suggested replacement language to avoid this issue: “Each circuit that is a monitored element of an IROL, assuming that all transmission elements are in service and the system is under normal conditions.”

2) B3. This item indicates that the circuits to be considered are to be agreed to by the plant owner and the Transmission Entity. Attachment B is applicable to the Planning Coordinator. If this item is by agreement by the plant and the Transmission Entity it should be removed from Attachment B and placed elsewhere in the document. If this is intended to apply to the Planning Coordinator, Transmission Entity should be replaced with Planning Coordinator.

3) B4. This criterion is overly stringent and should be deleted. The system is neither planned nor operated to allow for two overlapping outages without operator action in between. If this criterion is retained, it should be made consistent with the requirements of TPL-003 where operator actions can be assumed between the first and second contingencies. Since a similar comment was made previously, more information is being provided in this set of comments.1. Since the system is neither planned nor operated to two overlapping outages in between, such testing may result in unsolved cases, or voltages well below</td></tr>
</table>

Organization	Yes or No	Question 8 Comment
		criteria. In the case of an unsolved case, there are no flows to evaluate, making this standard impossible to apply. In the case of a solved case with voltages well below criteria, currents are likely to be incredibly high and therefore viewed as unrealistic. These concerns may limit the contingency selection to those which are not severe, eliminating any perceived benefit from this testing.2. There is no guidance provided on how the system should be dispatched in the model upon which the overlapping contingencies are tested. This will result in significant discrepancies between the base assumptions used by the various Planning Coordinators.
Response: Thank you for your comment. 1) In response to several comments on this subject the drafting team has replaced the reference to "determined in the long-term planning horizon" with "determined in the planning horizon pursuant to FAC-010." 2) This criterion applies to the Planning Coordinator and requires that the Planning Coordinator include circuits that form a path "(as agreed to by the plant owner 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" on the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2. This criterion applies specifically to nuclear plants for the purpose of supporting nuclear plant safe operation and shutdown. The drafting team believes the added reference to the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001 better reflects this intent. 3) The drafting team received several comments regarding "going beyond" TPL requirements by not simulating manual system adjustment in between contingencies. The purpose of this criterion is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. As such, criterion B4 does not require that all double contingency combinations be tested. It also does not require that the loadings respect the published applicable ratings of the circuits. It does require that engineering judgment be used to select certain combinations of line outages to be studied without manual system adjustment to ensure that, if the manual adjustments were not completed before the second contingency, the relay settings on the lines remaining in service would not inappropriately trip the lines.		
Duke Energy	No	1) B2 needs additional clarification, because identification could be in the short term or long term planning horizon. Suggested rewording: "B2. Each circuit that is a monitored Element of an IROL where the IROL was determined beyond the operating horizon." 2) B3 needs additional clarification, to explicitly identify the necessary agreement between the plant owner and Transmission Entity. Suggested rewording: "Each circuit that forms a path (as agreed to by the plant owner and the Transmission Entity pursuant to NUC-001) to supply off-site power to nuclear plants.
Response: Thank you for your comment. 1) In response to several comments on this subject the drafting team has replaced the reference to "determined in the long-term planning horizon" with		

Organization	Yes or No	Question 8 Comment
"determined in the planning horizon pursuant to FAC-010." 2) In response to comments on criterion B3 the drafting team has modified the criterion to refer explicitly to "the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001."		
Kansas City Power & Light	No	1) While we appreciate the drafting team's effort to refine the flowgate criteria from the last posting, the modifications do not go far enough and still do not reflect the use of flowgates. NERC's definition of flowgate includes two components. Let's focus on the first component which represents those flowgates defined in the IDC. Because IDC flowgates list is updated monthly and the IDC users can add temporary flowgates to the IDC at any time, this is an inappropriate list to use. We appreciate the drafting team's attempt to resolve this issue by including the caveat "that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator." However, this really only confuses the matter and does not solve it. Reliability Coordinators add flowgates to manage real-time congestion. Planning Coordinators do not. Per the NERC functional model, they do not even have a role in deciding which flowgates to add to the IDC. Flowgates are added to the IDC to mitigate existing, known congestion points not congestion points identified in a long-term planning study that may never materialize due to changing conditions. Thus, IDC flowgates should be specifically excluded. Now let us focus on the second component of flowgate. The second component is much like the first component in that is it a mathematical construct to analyze the impact of power flows on the BES except is not required to be included in the IDC. There is nothing in the definition of a flowgate to give credence that is represents anything more that point to calculate power flows and the impact of transactions. Flowgates are primarily used to manage congestion on the system and to sell transmission system. Because it is convenient to select a group of lines as a proxy to sell transmission service or manage congestion does not mean that those group of lines represent a reliability issue. Thus, we do not believe any flowgates should be included in the list. Any true reliability issues can be identified through the TPL studies and those facilities that do not meet the performance requirements are what should be used. 2) We do not support criterion B4. It exceeds what is required in the TPL standards and what is required per the reliability directive in Order 729. The TPL standards allow system operator intervention for category C3 contingencies between the two independent Category B contingencies. This standard should not exceed those requirements in the TPL standards. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test "must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning." Paragraph 80 states that "the test must be consistent with the general reliability principles embedded in the existing series of TPL" standards. Thus, exceeding the TPL standards could be argued as deviating from the directive. The directive is to be consistent not exceed. Exceeding the TPL standards is not consistency. In response to comments that did not support this criterion during the

Organization	Yes or No	Question 8 Comment
		first posting, the standards drafting team responded with "Testing multiple element contingencies while accounting for system adjustments between each element outage will not yield any facilities to be subject to PRC-023 as long as TPL-003 system performance requirements are met." We think the drafting team missed a basic point about the standard. The issue is not whether the registered entity develops and documents corrective action plans TPL-003-0a R2 and R3. The issue is if the system as currently designed meets the performance requirements in TPL-003-0a R1 which allows for operator interventions on Category C3 contingencies. For those C3 contingencies that don't currently meet the performance obligations after operator interventions, the subject facilities would be included PRC-023-2 R6 list of facilities.

Response: Thank you for your comment.

1) Congestion and system reliability are not mutually exclusive concerns. The Interchange Distribution Calculator (IDC) was developed to address reliability concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. The IDC is intended to identify and unload critical circuits that could become overloaded due to transactions. While Flowgates and the IDC are used to manage congestion, the underlying basis for doing so is to preserve system reliability.

   The Flowgate Methodology defines that Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. If monitored Facilities of flowgates do not meet the Relay Loadability requirements in PRC-023, violation of physical system limitations could occur, leading to instability, uncontrolled separation, or cascading outages. As such, it is appropriate and necessary to include monitored Facilities of flowgates as applicable circuits under PRC-023-2.

   The drafting team acknowledges that Planning Coordinators do not decide which flowgates are included in the IDC; however, the NERC Functional Model does indicate that Planning Coordinators are responsible for coordinating transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators. Thus it is appropriate that Planning Coordinators, in applying the criteria in Appendix B, provide a screening as to whether the monitored Facilities of a flowgate are added to the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2.

   Based on a number of comments, the drafting team has modified criterion B1 to refer to "permanent" flowgates and has replaced the reference to "long-term reliability concerns" with "reliability concerns for loading of that circuit." The drafting team believes this more clearly reflects the intent to exclude flowgates that are established on a temporary basis and more clearly identifies the role of the Planning Coordinator in applying criterion B1.

2) The drafting team received several comments regarding "going beyond" TPL requirements by not simulating manual system adjustment in between contingencies. The purpose of this criterion is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. As such, criterion B4 does not require that all double contingency combinations be tested. It also does not require that the loadings respect the published applicable ratings of the circuits. It does require that engineering judgment be used to select certain combinations of line outages to be studied without manual system adjustment to ensure that, if the manual adjustments were not completed before the second contingency, the relay settings on the lines remaining in service would not inappropriately trip the lines.

Organization	Yes or No	Question 8 Comment
American Transmission Company	Yes	
Orange and Rockland Utilities, Inc.	No	Why does B3 only apply to Nuclear Power Plants only?
Response: Thank you for your comment. This criterion applies specifically to nuclear plants for the purpose of supporting nuclear plant safe operation and shutdown. The drafting team believes the added reference to the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001 better reflects this intent.		
City of Jacksonville Beach, FL dba/Beaches Energy Services	Yes	Attachment B, the criterion in B4 seems rather arbitrary; but, the numbers seem reasonable.
Response: Thank you for your support.		
American Electric Power	No	Include the following refinements to the criteria for determining the facilities that must comply with the standard: 1) Add new B5 that reads: "Each circuit that is operated below 100 kV that the Regional Entity has identified as critical for the purposes of the Compliance Registry." 2) Renumber B5 to B6.o Need to consider the amount of load that is placed at risk when determining whether the circuit must comply with the standard. The threshold should be set at the DOE reporting level of 300 MW. 3) Need to include a review and appeals process as part of the annual assessment for the Planning Coordinator to review the proposed facilities with the transmission entity prior to adding those facilities to the Planning Coordinator's list of facilities that must comply with the standard.
Response: Thank you for your comment. 1) The drafting team believes it is appropriate to assess sub-100 kV circuits using the same methodology applied to Facilities operated at 100 kV to 200 kV. Requiring applicable entities to comply for all sub-100 kV circuits included on a critical facilities list defined by the Regional Entity results in a higher standard for sub-100 kV circuits, and is inconsistent with the directive in ¶60 of Order No. 733. 2) The criteria in Attachment B were selected to identify circuits that present a risk of cascading outages if relay loadability requirements are not met. The drafting team believes this is a sufficient basis without requiring an assessment of the amount of load at risk. However, the drafting team has modified criterion B5 in response to industry comments to require that if the Planning Coordinator selects a circuit based on technical studies or assessments, other		

Organization	Yes or No	Question 8 Comment
than those specified in criteria B1 through B4, that such selection is to be made in consultation with the Facility owner to provide the Facility owner an opportunity for input into the assessment. 3) An appeals process will be included in the NERC Rules of Procedure so that a Facility owner may appeal a decision in the event it believes a circuit is incorrectly identified by the Planning Coordinator		
Nebraska Public Power District	No	Attachment B, Criteria B1 could add at least 24 transmission elements which are transmission lines operated at 100kv to 200kv. After reviewing the MRO and SPP criteria these lines will not be included per PRC-023. Loss of any of these lines will not cause a cascading outage which PRC-023 is intended to prevent.
Response: Thank you for your comment. The drafting team has modified criterion B1 which may address the commenters concern. To the extent some of these circuits are still identified by criterion B1 the drafting team believes that these circuits do present the potential for cascading outages, although this potential may not be readily apparent when considering loss of any one of these circuits individually. An appeals process will be included in the NERC Rules of Procedure so that a Facility owner may appeal a decision in the event it believes a circuit is incorrectly identified by the Planning Coordinator.		
Great River Energy	No	1) While we appreciate the drafting team's effort to refine the flowgate criteria from the last posting, the modifications do not go far enough and still do not reflect the use of flowgates. NERC's definition of flowgate includes two components. Let's focus on the first component which represents those flowgates defined in the IDC. Because the IDC flowgates list is updated monthly and the IDC users can add temporary flowgates to it at any time, this is an inappropriate list to use. We appreciate the drafting team's attempt to resolve this issue by including the caveat "that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator." However, this really only confuses the matter and does not solve it. The Reliability Coordinator adds flowgates to manage real-time congestion. The Planning Coordinator does not. Per the NERC functional model, they do not even have a role in deciding which flowgates to add to the IDC. Flowgates are added to the IDC to mitigate existing, known congestion points not congestion points identified in a long-term planning study that may never materialize due to changing conditions. Thus, IDC flowgates should be specifically excluded.Now let us focus on the second component of flowgate. The second component is much like the first component in that it is a mathematical construct to analyze the impact of power flows on the BES except it is not required to be included in the IDC. There is nothing in the definition of a flowgate to give credence that it represents anything more that point to calculate power flows and the impact of transactions. Flowgates are primarily used to manage congestion on the system and to sell transmission system. Because it is convenient to select a group of lines as a proxy to sell transmission service or manage congestion does not mean that those group of lines represent a reliability issue. Thus, we do not believe

Organization	Yes or No	Question 8 Comment
		any flowgates should be included in the list. Any true reliability issues can be identified through the TPL studies and those facilities that do not meet the performance requirements are what should be used. 2) We do not support criterion B4. It exceeds what is required in the TPL standards and what is required per the reliability directive in Order 729. The TPL standards allow system operator intervention for category C3 contingencies between the two independent Category B contingencies. This standard should not exceed those requirements in the TPL standards. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test "must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning." Paragraph 80 states that "the test must be consistent with the general reliability principles embedded in the existing series of TPL" standards. Thus, exceeding the TPL standards could be argued as deviating from the directive. In response to comments that did not support this criterion during the first posting, the standards drafting team responded with "Testing multiple element contingencies while accounting for system adjustments between each element outage will not yield any facilities to be subject to PRC-023 as long as TPL-003 system performance requirements are met." We think the drafting team missed a basic point about the standard. The issue is not whether the registered entity develops and documents corrective actions plans per TPL-003-0a R2 and R3. The issue is if the system as currently designed meets the performance requirements in TPL-003-0a R1 which allows for operator interventions on Category C3 contingencies. For those C3 contingencies that don't currently meet the performance obligations after operator interventions, the subject facilities would be included PRC-023-2 R6 list of facilities.

Response: Thank you for your comment.

1) Congestion and system reliability are not mutually exclusive concerns. The Interchange Distribution Calculator (IDC) was developed to address reliability concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. The IDC is intended to identify and unload critical circuits that could become overloaded due to transactions. While Flowgates and the IDC are used to manage congestion, the underlying basis for doing so is to preserve system reliability.

   The Flowgate Methodology defines that Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. If monitored Facilities of flowgates do not meet the Relay Loadability requirements in PRC-023, violation of physical system limitations could occur, leading to instability, uncontrolled separation, or cascading outages. As such, it is appropriate and necessary to include monitored Facilities of flowgates as applicable circuits under PRC-023-2.

   The drafting team acknowledges that Planning Coordinators do not decide which flowgates are included in the IDC; however, the NERC Functional Model does indicate that Planning Coordinators are responsible for coordinating transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators. Thus it is appropriate that Planning Coordinators, in applying the criteria in Appendix B, provide a screening as to whether the monitored Facilities of a flowgate are

Organization	Yes or No	Question 8 Comment
added to the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2. Based on a number of comments, the drafting team has modified criterion B1 to refer to "permanent" flowgates and has replaced the reference to "long-term reliability concerns" with "reliability concerns for loading of that circuit." The drafting team believes this more clearly reflects the intent to exclude flowgates that are established on a temporary basis and more clearly identifies the role of the Planning Coordinator in applying criterion B1. 2) The drafting team received several comments regarding "going beyond" TPL requirements by not simulating manual system adjustment in between contingencies. The purpose of this criterion is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. As such, criterion B4 does not require that all double contingency combinations be tested. It also does not require that the loadings respect the published applicable ratings of the circuits. It does require that engineering judgment be used to select certain combinations of line outages to be studied without manual system adjustment to ensure that, if the manual adjustments were not completed before the second contingency, the relay settings on the lines remaining in service would not inappropriately trip the lines.		
Independent Electricity System Operator	No	1) We commented on Criterion 6 (now B4) related to TPL-003 Category C contingencies in the previous posting but we see no evidence that our comment was addressed. We therefore reiterate our position. The PC and TP assess their future systems according to the performance requirements stipulated in the TPL standards, including those in TPL-003. We question the requirement to have Planning Coordinators assess the impact of double contingencies with no manual system adjustments in between since this is not required by TPL-003. This goes beyond the basic planning and design requirements and in our view should be removed from Criterion B4. 2) We also believe Criterion B4 should be rewritten for greater clarity. The second bullet seems unnecessary since the post contingency loading on each circuit will not in fact be compared against its Facility Rating to determine applicability of PRC-023-2 but against the corresponding "applicability threshold". Also, the third bullet seems to conflict with the fourth, since the forth bullet allows for determining thresholds based on Facility Ratings that assume various loading durations, whereas the third bullet links determination of the threshold to the Facility Rating for a duration nearest four hours only. We therefore suggest the following alternative wording for B4:B4. Each circuit operated between 100 kV and 200 kV identified by applying the following procedure:B4.1Establish Thresholds of Applicability - (text of 4th bullet of B4)B4.2 Conduct Analysis - Conduct power flow analysis to simulate double contingency combinations selected by engineering judgment as indicated in TPL-003 Category C3.B4.3 Evaluate Applicability of PRC-023-2 - Compare post contingency loading of each circuit against its corresponding threshold determined in B4.1. Indicate the applicability of standard PRC-023-2 to each circuit for which the post contingency loading exceeds the corresponding threshold.B4.4 Exclusion - Radial circuits serving only load are excluded.
Response: Thank you for your comment.		

Organization	Yes or No	Question 8 Comment
1) The drafting team received several comments regarding "going beyond" TPL requirements by not simulating manual system adjustment in between contingencies. The purpose of this criterion is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. As such, criterion B4 does not require that all double contingency combinations be tested. It also does not require that the loadings respect the published applicable ratings of the circuits. It does require that engineering judgment be used to select certain combinations of line outages to be studied without manual system adjustment to ensure that, if the manual adjustments were not completed before the second contingency, the relay settings on the lines remaining in service would not inappropriately trip the lines. 2) Thank you for your comment regarding Facility Rating versus evaluation thresholds. We have modified the attachment to add clarity. The attachment now reads: • For circuits operated between 100 kV and 200 kV evaluate the post-contingency loading<u>, in consultation with the Facility owner,</u> against <u>a threshold based on</u> the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator.		
Northeast Utilities	Yes	
CenterPoint Energy	No	(a) Criterion B3 indicates any path that is used to supply off-site power to nuclear plants, as agreed to by the plant owner and the Transmission Entity. If the purpose of attachment B is to provide "bright line" criteria, then a negotiated agreement would not qualify as "bright line". Additionally, off-site power requirements are meant to ensure safe shutdown of nuclear reactors in a system restoration event where transmission lines are lightly loaded. CenterPoint Energy recommends criterion B3 be deleted. (b) Considering situations where the transmission system may be at risk of cascading outages or voltage collapse, sub-200 kV elements should be considered operationally significant only whenever reasonably contemplated scenarios would cause high amperage and low voltage to be experienced on the elements. Criteria B4.a in Attachment B proposes loading exceeding 115% of a two or four hour rating following a double contingency, without manual system adjustments. CenterPoint Energy believes this is not a technically sound method to indicate if an element is operationally significant.
Response: Thank you for your comment. (a) In response to comments on criterion B3 the drafting team has modified the criterion to refer explicitly to "the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001." The drafting team believes this modification to criterion B3 provides a level of measurability that should address the commenter's concern. (b) The drafting team received several comments regarding "going beyond" TPL requirements by not simulating manual system adjustment in between contingencies. The purpose of this criterion is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. As such, criterion B4 does not require that all double contingency combinations be tested. It also does not require that the loadings respect		

Organization	Yes or No	Question 8 Comment
the published applicable ratings of the circuits. It does require that engineering judgment be used to select certain combinations of line outages to be studied without manual system adjustment to ensure that, if the manual adjustments were not completed before the second contingency, the relay settings on the lines remaining in service would not inappropriately trip the lines.		
New York Independent System Operator	No	1) Flowgates are primarily used to manage congestion on the system and to sell transmission system. Because it is convenient to select a group of lines as a proxy to sell transmission service or manage congestion does not mean that those group of lines represent a reliability issue. Thus, flowgates should not be included in the list as currently specified in B1. Any true reliability issues can be identified through the TPL studies and those facilities that do not meet the performance requirements are what should be applicable here. 2) B2 adds significant confusion to the process. The long term planning horizon may include transmission projects which have not even been built or alternative system configurations which do not exist, making it impossible for affected parties to set their relays appropriately. Suggested replacement language to avoid this issue: "Each circuit that is a monitored element of an IROL, assuming that all transmission elements are in service and the system is under normal conditions." 3) B3 indicates that the circuits to be considered are to be agreed to by the plant owner and the Transmission Entity. Attachment B is applicable to the Planning Coordinator. If this item is by agreement by the plant and the Transmission Entity it should be removed from Attachment B and placed elsewhere in the document. If this is intended to apply to the Planning Coordinator, Transmission Entity should be replaced with Planning Coordinator. 4) The B4 criterion is overly stringent and should be deleted. The system is neither planned nor operated to allow for two overlapping outages without operator action in between. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test "must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning." Paragraph 80 states that "the test must be consistent with the general reliability principles embedded in the existing series of TPL" standards. If this criterion is retained, it should be made consistent with the requirements of TPL-003 where operator actions can be assumed between the first and second contingencies.
Response: Thank you for your comment. 1) Congestion and system reliability are not mutually exclusive concerns. The Interchange Distribution Calculator (IDC) was developed to address reliability concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. The IDC is intended to identify and unload critical circuits that could become overloaded due to transactions.		

Organization	Yes or No	Question 8 Comment
While Flowgates and the IDC are used to manage congestion, the underlying basis for doing so is to preserve system reliability. The Flowgate Methodology defines that Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. If monitored Facilities of flowgates do not meet the Relay Loadability requirements in PRC-023, violation of physical system limitations could occur, leading to instability, uncontrolled separation, or cascading outages. As such, it is appropriate and necessary to include monitored Facilities of flowgates as applicable circuits under PRC-023-2. The drafting team acknowledges that Planning Coordinators do not decide which flowgates are included in the IDC; however, the NERC Functional Model does indicate that Planning Coordinators are responsible for coordinating transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators. Thus it is appropriate that Planning Coordinators, in applying the criteria in Appendix B, provide a screening as to whether the monitored Facilities of a flowgate are added to the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2. Based on a number of comments, the drafting team has modified criterion B1 to refer to "permanent" flowgates and has replaced the reference to "long-term reliability concerns" with "reliability concerns for loading of that circuit." The drafting team believes this more clearly reflects the intent to exclude flowgates that are established on a temporary basis and more clearly identifies the role of the Planning Coordinator in applying criterion B1. 2) In response to several comments on this subject the drafting team has replaced the reference to "determined in the long-term planning horizon" with "determined in the planning horizon pursuant to FAC-010." 3) This criterion applies to the Planning Coordinator and requires that the Planning Coordinator include circuits that form a path "(as agreed to by the plant owner 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" on the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2. This criterion applies specifically to nuclear plants for the purpose of supporting nuclear plant safe operation and shutdown. The drafting team believes the added reference to the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001 better reflects this intent. 4) The drafting team received several comments regarding "going beyond" TPL requirements by not simulating manual system adjustment in between contingencies. The purpose of this criterion is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. As such, criterion B4 does not require that all double contingency combinations be tested. It also does not require that the loadings respect the published applicable ratings of the circuits. It does require that engineering judgment be used to select certain combinations of line outages to be studied without manual system adjustment to ensure that, if the manual adjustments were not completed before the second contingency, the relay settings on the lines remaining in service would not inappropriately trip the lines.		
Consolidated Edison Co. of NY, Inc.	No	Attachment B - Why does B3 only apply to Nuclear Power Plants only?
Response: Thank you for your comment. This criterion applies specifically to nuclear plants for the purpose of supporting nuclear plant safe operation and shutdown. The drafting team believes the added		

Organization	Yes or No	Question 8 Comment
reference to the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001 better reflects this intent.		
Ameren	No	1) Criterion B1, which has been modified to encompass only flowgates which have been included to address long-term reliability concerns, while a step in the right direction, does not go far enough. Because flowgates are primarily utilized to manage congestion and assist in the process of transmission service sales, rather than investigate reliability issues more appropriately conducted via study work covered under the TPL standards, this criteria should be eliminated. 2) Criterion B4 as worded still exceeds the requirements of Reliability Standard TPL-003 by requiring simulating double contingencies with no operator intervention permitted. While such simulation would be done as part of assessment work under TPL-003 for fast-acting contingencies involving multiple circuits, such as Category C1 bus faults, C2 breaker failures, and C5 double-circuit tower outages, such simulations are not necessary under TPL-003 with Category C3 events which consist of separate Category B events with intervening operator action. Such simulations should not be made necessary as part of the proposed PRC-023-2 standard. Rather, should the TPL-003 performance requirements not be met for Category C3 contingencies with operator intervention considered, those facilities could be included in the list of facilities specified in PRC-023-2 Requirement R6.

Response: Thank you for your comment.

1) Congestion and system reliability are not mutually exclusive concerns. The Interchange Distribution Calculator (IDC) was developed to address reliability concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. The IDC is intended to identify and unload critical circuits that could become overloaded due to transactions. While Flowgates and the IDC are used to manage congestion, the underlying basis for doing so is to preserve system reliability.

   The Flowgate Methodology defines that Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. If monitored Facilities of flowgates do not meet the Relay Loadability requirements in PRC-023, violation of physical system limitations could occur, leading to instability, uncontrolled separation, or cascading outages. As such, it is appropriate and necessary to include monitored Facilities of flowgates as applicable circuits under PRC-023-2.

   The drafting team acknowledges that Planning Coordinators do not decide which flowgates are included in the IDC; however, the NERC Functional Model does indicate that Planning Coordinators are responsible for coordinating transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators. Thus it is appropriate that Planning Coordinators, in applying the criteria in Appendix B, provide a screening as to whether the monitored Facilities of a flowgate are added to the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2.

   Based on a number of comments, the drafting team has modified criterion B1 to refer to “permanent” flowgates and has replaced the reference to “long-term reliability concerns” with “reliability concerns for loading of that circuit.” The drafting team believes this more clearly reflects the intent to exclude flowgates that are established on a temporary basis and more clearly identifies the role of the Planning Coordinator in applying criterion B1.

Organization	Yes or No	Question 8 Comment
2) The drafting team received several comments regarding “going beyond” TPL requirements by not simulating manual system adjustment in between contingencies. The purpose of this criterion is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. As such, criterion B4 does not require that all double contingency combinations be tested. It also does not require that the loadings respect the published applicable ratings of the circuits. It does require that engineering judgment be used to select certain combinations of line outages to be studied without manual system adjustment to ensure that, if the manual adjustments were not completed before the second contingency, the relay settings on the lines remaining in service would not inappropriately trip the lines.		
National Grid	No	1. As per Section 4.2.3 (also included as bullet point 2 of Applicable circuits in Attachment B) "Transmission Lines operated below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry and the Planning Coordinator has determined are required to comply with this standard." National Grid believes that voltage levels less than 100 kV are outside NERC's jurisdiction and hence, requirements related to sub 100 kV levels should not be part of NERC standards. 2. National Grid recommends a provision in the standard which allows entities an option to 1. Either comply with standard for all applicable elements or 2. Apply the methodology as stated in Attachment B. The rationale is that entities that choose to comply with PRC-023 for all applicable elements should be recognized and should be exempted from complying with the methodology in Attachment B. 3. Requirement R6 of the proposed standard requires entities to apply criteria in Attachment B and conduct assessments with no more than 15 months between assessments to determine which transmission elements must comply with this standard. TPL standard which is considered to be the primary standard dealing with designing and planning of the system allows an interim assessment to rely on previous years simulations and does not mandate a stringent 15 month period between assessments. National Grid believes that an auxiliary PRC-023 standard should not present more stringent requirements than the primary TPL standard and recommends to remove the "15 month between assessments" requirement.
Response: Thank you for your comment. 1) The drafting team understands the concern with including facilities operated below 100 kV; however, the NERC Statement of Compliance Registry Criteria does allow Regional Entities the ability to identify such facilities operated below 100 kV as required to comply with NERC Reliability Standards. The drafting team has replaced the phrase “critical for the purposes of the Compliance Registry” with text from the ¶60 of Order No. 733, which references text in section III.d.2 of the NERC Statement of Compliance Registry Criteria. So the second category of circuits to be evaluated now refers to transmission lines and transformers operated below 100 kV “that are included on a critical facilities list defined by the Regional Entity.” The drafting team made corresponding modifications to the Applicability section. 2) The drafting team has added a new criterion B6 to include any circuit mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner. Any circuit identified by criterion B6 would not require application of the other criteria in Attachment B.		

Organization	Yes or No	Question 8 Comment
3) The drafting team intended that an assessment be performed each year, but that the power flow analyses used to support the assessment need not be performed unless material changes to the system have occurred since the last assessment. The drafting team has added a footnote to criterion B4 to clarify this intent.		
ERCOT ISO	No	1) In regards to criteria B1, the Texas Interconnection does not have comparable monitored elements. All transmission elements are treated and monitored equally in ERCOT at this time. The only exception to this is IROLs which are already covered in criteria B2. Therefore, ERCOT ISO suggests removing the reference to the Texas Interconnection in criteria B1. 2) In regards to criteria B3, the Planning Coordinator does not necessarily know the circuit paths for off-site power for nuclear plants. The Transmission Owners would be better able to identify these circuits. ERCOT ISO suggests moving this criteria into section 4.2 (Applicability, Facilities). 3) ERCOT ISO also suggests revising the language so that it does not state that a "circuit must comply with the standard" since it is an entity that must comply with the standard. ERCOT ISO suggests replacing this language with "circuit will be applicable to this standard" throughout Attachment B.
Response: Thank you for your comment. 1) The reference to the Texas Interconnection has been removed. The drafting team agrees that in the Texas Interconnection criterion B2 will identify the appropriate circuits. 2) In response to comments on criterion B3 the drafting team has modified the criterion to refer explicitly to "the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001." The drafting team believes this list of facilities is available to the Planning Coordinator. 3) The drafting team has modified the document as suggested to reflect that the applicable entities are responsible for complying with the standard. The introductory sentence in Attachment B now reads, "If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit."		
MidAmerican Energy	No	Criterion B1 should be eliminated as there is no technical basis to show that "flowgates" are anything more than a measure of congestion. The loss or potential loss of a flowgate won't necessarily result in any more or less reliability impact to the BES than the loss of any other BES element. Therefore a superior criteria for Attachment B is to actually base critical elements upon the Federal Power Act Section 215 criteria of instability, uncontrolled separation, or cascading, which is related to the B2 criteria and being an IROL. Measuring the potential exceedance of TPL criteria as written is also acceptable. MidAmerican notes the NERC Attachment B criteria exceed the FERC directive to follow TPL criteria in Order 729.
Response: Thank you for your comment. Congestion and system reliability are not mutually exclusive concerns. The Interchange Distribution Calculator (IDC) was developed to address reliability		

Organization	Yes or No	Question 8 Comment
concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. The IDC is intended to identify and unload critical circuits that could become overloaded due to transactions. While Flowgates and the IDC are used to manage congestion, the underlying basis for doing so is to preserve system reliability. The Flowgate Methodology defines that Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. If monitored Facilities of flowgates do not meet the Relay Loadability requirements in PRC-023, violation of physical system limitations could occur, leading to instability, uncontrolled separation, or cascading outages. As such, it is appropriate and necessary to include monitored Facilities of flowgates as applicable circuits under PRC-023-2. The drafting team acknowledges that Planning Coordinators do not decide which flowgates are included in the IDC; however, the NERC Functional Model does indicate that Planning Coordinators are responsible for coordinating transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators. Thus it is appropriate that Planning Coordinators, in applying the criteria in Appendix B, provide a screening as to whether the monitored Facilities of a flowgate are added to the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2. Based on a number of comments, the drafting team has modified criterion B1 to refer to “permanent” flowgates and has replaced the reference to “long-term reliability concerns” with “reliability concerns for loading of that circuit.” The drafting team believes this more clearly reflects the intent to exclude flowgates that are established on a temporary basis and more clearly identifies the role of the Planning Coordinator in applying criterion B1.		
Xcel Energy	No	B1) The NERC book of flowgates for the Eastern Interconnection includes a combination of permanent and temporary flowgates. This criterion should only use the permanent flowgates and the text should be modified as indicated to reflect that. Each circuit that is a monitored Element 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 Element in the Texas Interconnection or Québec Interconnection, that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator. B3) This appears to link to the NUC-001 standard. We would suggest the following modification:"Each circuit that forms a path (as agreed to by the plant owner and the Transmission Entity) to supply off-site power to nuclear plants as established in the NPIR for NUC-001." B5) We suggest removing this one as it is too open-ended and open to interpretation as to which additional circuits should be considered. If there are additional criteria that are determined later that should be included, then we suggest they be added by either a regional standard or a SAR to modify the NERC standard.
Response: Thank you for your comment. B1) The drafting team has modified criterion B1 based on a number of comments related to temporary versus permanent flowgates. The drafting team believes these modifications address the commenter’s concern. B3) Thank you for your suggestion. In response to comments on criterion B3 the drafting team has modified the criterion to refer explicitly to “the Nuclear Plant		

Organization	Yes or No	Question 8 Comment
Interface Requirements (NPIRs) pursuant to NUC-001.” B5) The drafting team has modified criterion B5 in response to industry comments to require that if the Planning Coordinator selects a circuit based on technical studies or assessments, other than those specified in criteria B1 through B4, that such selection is to be made in consultation with the Facility owner to provide the Facility owner an opportunity for input into the assessment. Additionally, an appeals process will be included in the NERC Rules of Procedure so that a Facility owner may appeal a decision in the event it believes a circuit is incorrectly identified by the Planning Coordinator.		

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Ballot Pool Open November 1 – December 2, 2010
Comment Period Open November 1 – December 16, 2010

Now available at: http://www.nerc.com/filez/standards/SAR_Project%202010-13_Order%20733%20Relay%20Modifiations.html

Project 2010-13: Revisions to Relay Loadability for Order 733

PRC-023-2 – Transmission Relay Loadability has been posted for a 45-day formal comment period, and a ballot pool is being formed during the first 30 days of the 45-day comment period.

Ballot Pool Open through 8 a.m. on December 2, 2010

A ballot pool is being formed during the first 30 days of the 45-day formal comment period, and an initial ballot will be conducted during the last 10 days of this comment period.

Registered Ballot Body members may join the ballot pool to be eligible to vote in the upcoming ballot at the following page: https://standards.nerc.net/BallotPool.aspx

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list server for this ballot pool is: bp-2010-13_Rev RLO 733_in

Formal 45-day Comment Period Open through 8 p.m. on December 16, 2010

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Monica Benson at monica.benson@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page:
http://www.nerc.com/filez/standards/SAR_Project%202010-13_Order%20733%20Relay%20Modifiations.html

Next Steps

An initial ballot will be conducted during the last 10 days of the 45-day formal comment period. The drafting team will consider all comments (those submitted with a comment form, and those submitted with a ballot) and will determine whether to make additional changes to the standard. The team will post its response to comments and, if the standard has only minor changes, will post the standard and conduct a 10-day recirculation ballot.

Project Background

When FERC issued Order 733, approving PRC-023-1 — Transmission Relay Loadability, it directed several changes to that standard and also directed development of one or more new standards within specified time periods. NERC filed for clarification and rehearing asking for clarity and an extension of time to address the directives; however, without a response to the requests for clarification and rehearing, NERC must progress as though these requests will be denied.

The SAR for Project 2010-13 subdivides the standard-development-related directives into three phases. Phase I

addresses the specific directives from Order 733 that identified required modifications to various elements within PRC-023-1. Phase II addresses directives associated with development of a new standard to address generator relay loadabilty. Phase III addresses directives associated with writing requirements to address protective relay operations due to power swings.

Applicability of Proposed PRC-023-2

Distribution Providers that own specific facilities (see standard for details)
Generator Owners that own specific facilities (see standard for details)
Planning Coordinators
Transmission Owners that own specific facilities (see standard for details)

Standards 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 Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

North American Electric Reliability Corporation
116-390 Village Blvd.
Princeton, NJ 08540
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NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Initial Ballot Open December 7 – 16, 2010
Project 2010-13: Revisions to Relay Loadability for Order 733

Available December 7th at: https://standards.nerc.net/CurrentBallots.aspx

Initial Ballot Window: December 7-16, 2010

An initial ballot for PRC-023-2 – Transmission Relay Loadability will be open from 8 a.m. Eastern on December 7, 2010 through 8 p.m. Eastern on Thursday, December 16, 2010.

Instructions

During the initial ballot window, members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Related Comment Period

A concurrent formal comment period is underway for PRC-023-2. Comments may be submitted using this electronic form. The comment period and ballot will both end on December 16, 2010. More information is available on the project page.

Next Steps

At the conclusion of the ballot period, the drafting team will consider all comments (those submitted with a comment form, and those submitted with a ballot) and will determine whether to make additional changes to the standard. The team will post its response to comments and, if the standard has only minor changes, will post the standard and conduct a 10-day recirculation ballot.

Project Background

When FERC issued Order 733, approving PRC-023-1 — Transmission Relay Loadability, it directed several changes to that standard and also directed development of one or more new standards within specified time periods. NERC filed for clarification and rehearing asking for clarity and an extension of time to address the directives; however, without a response to the requests for clarification and rehearing, NERC must progress as though these requests will be denied.

The SAR for Project 2010-13 subdivides the standard-development-related directives into three phases. Phase I addresses the specific directives from Order 733 that identified required modifications to various elements within PRC-023-1. Phase II addresses directives associated with development of a new standard to address generator relay loadability. Phase III addresses directives associated with writing requirements to address protective relay operations due to power swings.

Applicability of Proposed PRC-023-2

Distribution Providers that own specific facilities (see standard for details)
Generator Owners that own specific facilities (see standard for details)

Planning Coordinators
Transmission Owners that own specific facilities (see standard for details)

Standards Process

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For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

Ballot Results

Ballot Name:	Project 2010-13_Revisions to Relay Loadability for Order 733_in
Ballot Period:	12/7/2010 - 12/16/2010
Ballot Type:	Initial
Total # Votes:	286
Total Ballot Pool:	325
Quorum:	88.00 % The Quorum has been reached
Weighted Segment Vote:	51.51 %
Ballot Results:	The standard will proceed to recirculation ballot.

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	97	1	47	0.573	35	0.427	6	9
2 - Segment 2.	11	0.9	1	0.1	8	0.8	1	1
3 - Segment 3.	73	1	30	0.577	22	0.423	9	12
4 - Segment 4.	21	1	10	0.667	5	0.333	4	2
5 - Segment 5.	67	1	29	0.592	20	0.408	10	8
6 - Segment 6.	38	1	17	0.548	14	0.452	3	4
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.5	2	0.2	3	0.3	1	1
9 - Segment 9.	5	0.2	2	0.2	0	0	2	1
10 - Segment 10.	6	0.5	2	0.2	3	0.3	0	1
Totals	**325**	**7.1**	**140**	**3.657**	**110**	**3.443**	**36**	**39**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Jason Shaver	Affirmative	View
1	APS	Barbara McMinn	Affirmative	
1	Arizona Public Service Co.	Robert D Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott Kinney	Affirmative	

1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Beaches Energy Services	Joseph S. Stonecipher	Negative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	CenterPoint Energy	Paul Rocha	Negative	View
1	Central Maine Power Company	Kevin L Howes	Negative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Negative	View
1	City of Vero Beach	Randall McCamish	Affirmative	View
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	View
1	Colorado Springs Utilities	Paul Morland	Negative	View
1	Commonwealth Edison Co.	Gregory Campbell	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	View
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	John K Loftis	Affirmative	
1	Duke Energy Carolina	Douglas E. Hils	Negative	
1	East Kentucky Power Coop.	George S. Carruba	Abstain	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Negative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Gainesville Regional Utilities	Luther E. Fair	Affirmative	
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Negative	View
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Negative	View
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stan T. Rzad	Affirmative	View
1	Lake Worth Utilities	Walt Gill	Affirmative	View
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Negative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	View
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Richard Burt	Negative	View
1	National Grid	Saurabh Saksena	Negative	View
1	Nebraska Public Power District	Richard L. Koch	Affirmative	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Negative	View
1	New York Power Authority	Arnold J. Schuff	Negative	
1	Northeast Utilities	David H. Boguslawski	Negative	View
1	Northern Indiana Public Service Co.	Kevin M Largura	Negative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Omaha Public Power District	Douglas G Peterchuck	Affirmative	
1	Oncor Electric Delivery	Michael T. Quinn	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas	Negative	View
1	PacifiCorp	Colt Norrish	Negative	View
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Negative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Catherine Koch		
1	Rochester Gas and Electric Corp.	John C. Allen	Negative	View

1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	Santee Cooper	Terry L. Blackwell	Negative	
1	SCE&G	Henry Delk, Jr.	Affirmative	
1	Seattle City Light	Pawel Krupa	Abstain	
1	Sierra Pacific Power Co.	Rich Salgo	Negative	View
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	View
1	South Texas Electric Cooperative	Richard McLeon	Abstain	
1	Southern California Edison Co.	Dana Cabbell		
1	Southern Company Services, Inc.	Horace Stephen Williamson	Affirmative	
1	Southern Illinois Power Coop.	William G. Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	
1	Texas Municipal Power Agency	Frank J. Owens		
1	Transmission Agency of Northern California	James W. Beck		
1	Tri-State G & T Association, Inc.	Keith V. Carman	Negative	View
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Negative	View
1	Westar Energy	Allen Klassen	Affirmative	View
1	Western Area Power Administration	Brandy A Dunn	Negative	View
1	Western Farmers Electric Coop.	Forrest Brock	Affirmative	View
1	Xcel Energy, Inc.	Gregory L Pieper	Negative	View
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Gregory Van Pelt	Negative	View
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Negative	View
2	Independent Electricity System Operator	Kim Warren	Negative	View
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Jason L Marshall	Negative	View
2	New Brunswick System Operator	Alden Briggs	Negative	View
2	New York Independent System Operator	Gregory Campoli	Negative	View
2	PJM Interconnection, L.L.C.	Tom Bowe		
2	Southwest Power Pool	Charles H Yeung	Negative	View
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Negative	View
3	American Electric Power	Raj Rana	Negative	View
3	Anaheim Public Utilities Dept.	Kelly Nguyen	Abstain	
3	APS	Steven Norris	Affirmative	
3	Arkansas Electric Cooperative Corporation	Philip Huff	Affirmative	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	Avista Corp.	Robert Lafferty	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blue Ridge Power Agency	Duane S. Dahlquist		
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	Central Hudson Gas & Electric Corp.	Thomas C Duffy		
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Farmington	Linda R. Jacobson	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Abstain	
3	City of Leesburg	Phil Janik		
3	Cleco Corporation	Michelle A Corley	Negative	View
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Cowlitz County PUD	Russell A Noble	Negative	View
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Affirmative	View
3	Duke Energy Carolina	Henry Ernst-Jr	Negative	View
3	East Kentucky Power Coop.	Sally Witt	Abstain	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Negative	View
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power Corporation	Lee Schuster	Affirmative	

3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Abstain	
3	Great River Energy	Sam Kokkinen	Affirmative	
3	Hydro One Networks, Inc.	David L Kiguel	Negative	View
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory David Woessner		
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	Manitoba Hydro	Greg C. Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Affirmative	
3	Muscatine Power & Water	John S Bos	Negative	
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	Marilyn Brown	Negative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Negative	
3	Northern Indiana Public Service Co.	William SeDoris	Negative	
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Abstain	
3	PacifiCorp	John Apperson	Negative	View
3	PECO Energy an Exelon Co.	Vincent J. Catania		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Abstain	
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Negative	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young	Affirmative	
3	Southern California Edison Co.	David Schiada		
3	Tacoma Public Utilities	Travis Metcalfe	Negative	View
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	
3	Tri-State G & T Association, Inc.	Janelle Marriott	Negative	View
3	Wisconsin Electric Power Marketing	James R. Keller	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Negative	View
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	American Public Power Association	Allen Mosher	Affirmative	
4	Arkansas Electric Cooperative Corporation	Ronnie Frizzell	Affirmative	
4	Central Lincoln PUD	Shamus J Gamache	Negative	View
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Affirmative	View
4	Consumers Energy	David Frank Ronk	Negative	View
4	Cowlitz County PUD	Rick Syring	Negative	View
4	Detroit Edison Company	Daniel Herring		
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards	Affirmative	View
4	Georgia System Operations Corporation	Guy Andrews	Abstain	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	View
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
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	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	Tacoma Public Utilities	Keith Morisette	Negative	View
4	Tallahassee Electric	Allan Morales	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5		Edwin B Cano	Affirmative	

5	AEP Service Corp.	Brock Ondayko	Negative	View
5	Amerenue	Sam Dwyer	Negative	
5	APS	Mel Jensen	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	City and County of San Francisco	Daniel Mason		
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Negative	View
5	City of Tallahassee	Alan Gale	Abstain	
5	Cleco Power	Stephanie Huffman	Negative	View
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	View
5	Consumers Energy	James B Lewis	Negative	View
5	Covanta Energy	Samuel Cabassa	Negative	
5	Cowlitz County PUD	Bob Essex	Negative	View
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Negative	
5	East Kentucky Power Coop.	Stephen Ricker		
5	El Paso Electric Company	Alfred W Morgan		
5	Electric Power Supply Association	Jack Cashin	Abstain	
5	Energy Northwest - Columbia Generating Station	Doug Ramey	Affirmative	
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	Florida Municipal Power Agency	David Schumann	Affirmative	View
5	Great River Energy	Cynthia E Sulzer	Affirmative	
5	Green Country Energy	Greg Froehling	Affirmative	
5	Indeck Energy Services, Inc.	Rex A Roehl		
5	Kansas City Power & Light Co.	Scott Heidtbrink		
5	Kissimmee Utility Authority	Mike Blough	Abstain	
5	Lakeland Electric	Thomas J Trickey	Affirmative	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin		
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New Harquahala Generating Co. LLC	Nicholas Q Hayes	Affirmative	
5	New York Power Authority	Gerald Mannarino	Negative	View
5	Northern California Power Agency	Tracy R Bibb		
5	Northern Indiana Public Service Co.	Michael K Wilkerson	Negative	
5	Occidental Chemical	Michelle DAntuono	Negative	View
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas	Affirmative	
5	Pacific Gas and Electric Company	Richard J. Padilla	Negative	View
5	PacifiCorp	Sandra L. Shaffer	Negative	View
5	Platte River Power Authority	Pete Ungerman	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	Progress Energy Carolinas	Wayne Lewis	Affirmative	
5	PSEG Power LLC	Jerzy A Slusarz	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones	Affirmative	
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	George T. Ballew	Affirmative	
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.	Abstain	
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Abstain	

5	Xcel Energy, Inc.	Liam Noailles	Negative	View
6	AEP Marketing	Edward P. Cox	Negative	View
6	Ameren Energy Marketing Co.	Jennifer Richardson		
6	Arizona Public Service Co.	Justin Thompson	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	View
6	Cleco Power LLC	Robert Hirchak	Negative	View
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Negative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Negative	View
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	View
6	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	View
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	New York Power Authority	William Palazzo	Negative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Negative	View
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Negative	View
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Abstain	
6	Progress Energy	John T Sturgeon	Affirmative	
6	PSEG Energy Resources & Trade LLC	James D. Hebson	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	RRI Energy	Trent Carlson		
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Mike Hummel	Affirmative	
6	Santee Cooper	Suzanne Ritter	Negative	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	View
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	
6	Western Area Power Administration - UGP Marketing	John Stonebarger		
6	Xcel Energy, Inc.	David F. Lemmons	Negative	View
8		Roger C Zaklukiewicz	Negative	View
8		James A Maenner	Abstain	
8		Edward C Stein	Affirmative	
8	INTELLIBIND	Kevin Conway	Affirmative	
8	JDRJC Associates	Jim D. Cyrulewski	Negative	
8	Utility Services, Inc.	Brian Evans-Mongeon		
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	California Energy Commission	William Mitchell Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Abstain	View
9	Oregon Public Utility Commission	Jerome Murray	Abstain	
9	Snohomish County PUD No. 1	William Moojen	Affirmative	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	New York State Reliability Council	Alan Adamson	Negative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Negative	View
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	View
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool Regional Entity	Stacy Dochoda		
10	Texas Reliability Entity	Larry D. Grimm	Negative	View

Legal and Privacy : 609.452.8060 voice : 609.452.9550 fax : 116-390 Village Boulevard : Princeton, NJ 08540-5721
Washington Office: 1120 G Street, N.W. : Suite 990 : Washington, DC 20005-3801

Account Log-In/Register

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Initial Ballot Results

Project 2010-13 - Relay Loadability for Order 733

Now available at: https://standards.nerc.net/Ballots.aspx

An initial ballot of PRC-023-2 — Transmission Relay Loadability ended on December 16, 2010. Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results.

Ballot for Standard:

- Quorum: 88.00 %
- Approval: 51.51%

Project Background:

When FERC issued Order 733, approving PRC-023-1 — Transmission Relay Loadability, it directed several changes to that standard and also directed development of one or more new standards within specified time periods. NERC filed a request for clarification and rehearing and requested additional time to address the directives; however, pending FERC's response to the requests for clarification and additional time, NERC must progress as though these requests will be denied.

The SAR for Project 2010-13 subdivides the standard-development-related directives into three phases. Phase I addresses the specific directives from Order 733 that identified required modifications to various elements within PRC-023-1. Phase II addresses directives associated with development of a new standard to address generator relay loadability. Phase III addresses directives associated with writing requirements to address protective relay operations due to power swings.

More details may be found on the project page:
http://www.nerc.com/filez/standards/SAR_Project%202010-13_Order%20733%20Relay%20Modifiations.html

Next Steps

The drafting team will consider all comments (those submitted with a comment form and those submitted with a ballot) and will determine whether to make additional changes to the standard. The team will post its response to comments and, if the standard has only minor changes, will post the standard and conduct a 10-day recirculation ballot. The team will also conduct a non-binding poll of the VRFs and VSLs.

Ballot Criteria

Approval requires both (1) a quorum, which is established by at least 75% of the members of the ballot pool submitting either an affirmative vote, a negative vote, or an abstention, and (2) a two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and non-responses.

Standards 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 Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot — Revisions to Relay Loadability for Order 733 (Project 2010-13)
Date of Initial Ballot: December 7-16, 2010

Summary Consideration: A 45-day formal comment period with a concurrent ballot during the last 10 days of the comment period was conducted for the Transmission Relay Loadability Version 2 standard PRC-023-2 from November 1, 2010 to December 1-16, 2010 and achieved a quorum of 88.00% and a weighted segment approval of 51.51%.

Commenters noted inconsistencies and redundancy between the Applicability section, Parts 6.1 and 6.2 of Requirement R6 and Attachment B. The drafting team agrees that inconsistency between these sections of the standard will lead to confusion. The drafting team has removed parts 6.1 and 6.2 from Requirement R6 to avoid redundancy, and has revised the Applicability section and Attachment B based on industry comments to provide consistency and clarity.

Commenters expressed concern that 24 months was not enough time to implement protection system modifications when the Planning Coordinator identifies circuits for which the applicable entity must comply with the standard. The drafting team considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1.

Commenters expressed concern with use of the phrase critical facilities for purposes of the Compliance Registry. The drafting team modified this reference related to circuits operated below 100 kV by replacing the phrase “critical for the purposes of the Compliance Registry” with text from ¶60 of Order No. 733, which references text in section III.d.2 of the NERC Statement of Compliance Registry Criteria. The second category of circuits to be evaluated now refers to transmission lines and transformers operated below 100 kV “that are included on a critical facilities list defined by the Regional Entity.”

Commenters expressed concern with criterion 10 citing that additional specificity is necessary to clarify a number of issues. In response to comments the drafting team added a footnote to criterion 10 to clarify that use of the phrase “mechanical withstand” is based on the “dotted line” in IEEE C57.109-1993 – *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4. The drafting team also moved the requirement for fault protection to a separate part of criterion 10 to clarify it applies only to load responsive transformer fault protection relays, and only when such relays are used.

Some commenters expressed concern that reporting associated with certain criteria under Requirement R1 duplicates requirements in FAC-008 and FAC-009. The drafting team explained that the FAC standards pertain to developing and transmitting ratings and rating methodologies, whereas PRC-023 requires notification when the certain Facility Ratings are used in assessing relay loadability

Some commenters expressed concern with complying with Requirement R2. The drafting team noted that Requirement R2 does not add a new obligation on Transmission Owners, Generator Owners, and Distribution Providers; it only explicitly states in PRC-023-2 an obligation that presently is included in Attachment A, Section 2 of PRC-023-1.

Some commenters questioned the need to differentiate between certain types communication-assisted protection systems. The drafting team noted that the distinction in Attachment A, Section 1.6 is appropriate, because current -differential telecommunications systems are different than other telecommunications systems, in that the sensitivities for the protection elements are often set very sensitively – well below load current – and depend on the integrity of the channel to make a trip/no trip decision where other telecommunication system technologies require the operation of other protection system elements (usually distance elements) which are already subject to the requirements of this standard. Therefore, they will trip immediately due to load current upon the loss of communications, and are dependent on the fault detectors to inhibit trip.

Many commenters expressed their belief that flowgates are market-based tools that are not appropriate for use in assessing system reliability. The drafting team responded that congestion and system reliability are not mutually exclusive concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. While flowgates are used to manage congestion, the underlying basis for doing so is to preserve system reliability. As such, it is appropriate and necessary to include monitored Facilities of flowgates as applicable circuits under PRC-023-2.

Commenters indicated clarification is needed to identify which Interconnection Reliability Operating Limits (IROLs) are to be considered in application of Attachment B, criterion B2. In response to several comments on this subject, the drafting team has replaced the reference to “determined in the long-term planning horizon” with “determined in the planning horizon pursuant to FAC-010”.

A number of commenters expressed concern that the description of transmission paths that supply off-site power to nuclear power plants lacked measurability. The drafting team has added a reference to Nuclear Plant Interface Requirements (NPIRs) developed pursuant to NUC-001. The drafting team also clarified that this criterion applies specifically to nuclear plants for the purpose of supporting nuclear plant safe operation and shutdown.

The drafting team received several comments regarding “going beyond” TPL requirements by not simulating manual system adjustment in between contingencies in Attachment B, criterion B4. The purpose of this criterion is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage if manual adjustments were not completed before the second contingency. The drafting team also clarified that while an assessment must be performed each year, the power flow analyses used to support the assessment need not be performed unless material changes to the system have occurred since the last assessment. The drafting team has added a footnote to criterion B4 to clarify this intent.

Commenters expressed concern that the criteria in Attachment B, criterion B5 in particular, provide too much autonomy to the Planning Coordinator. The drafting team added to some of the criteria that the Planning Coordinator shall consult with the Facility owner when performing its assessment to provide the Facility owner an opportunity for input into the assessment. Additionally, an appeals process will be included in the NERC Rules of Procedure so that a Facility owner may appeal a decision in the event it believes a circuit is incorrectly identified by the Planning Coordinator.

Several commenters expressed concern that Requirement R7 creates a potential for double jeopardy. The drafting team understands the double jeopardy concern and has deleted Requirement R7. The Effective Dates section has been modified to address the timeline in which Facility owners must comply with Requirements R1 and R5 when the Planning Coordinator identifies a circuit for which the Facility owner must comply with the standard.

One commenter requested that the exception for "switch on to fault" schemes be added back in. The drafting team understands the commenter’s concern that the proposed implementation plan for PRC-023-2 had the unintended consequence of shortening the time provided for Facility owners to comply with Requirement R1 for switch-on-to-fault schemes. The drafting team has modified the effective dates in the standard to address this problem.

A limited number of commenters expressed concern that the criteria for verifying relay loadability in Requirement R1 may not be directly applicable to circuits operated below 100 kV. The drafting team understands this concern and this item has been placed in the issues database for future consideration in the next general revision of the standard. The drafting team notes that PRC-023-1 already applies to lines operated at 100 kV to 200 kV and the drafting team does not believe that a significant number of sub-100 kV circuits will be impacted. As such, the drafting team disagrees that more research is required prior to implementing PRC-023-2.

If you feel that the drafting team overlooked your comments, 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, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

<table>
<tr><th>Voter</th><th>Entity</th><th>Seg-ment</th><th>Vote</th><th>Comment</th></tr>
<tr><td>Roger C Zaklukiewicz</td><td></td><td>8</td><td>Negative</td><td>Concern with the possible interpretation of the wording in Requirement 1, Criteria 10. The wording needs to be clarified.</td></tr>
<tr><td colspan="5">Response: Thank you for your comment.

The text of the standard has been modified to clarify the intent of criterion 10. Specifically, a footnote has been added to criterion 10 to clarify that use of the phrase “mechanical withstand” is based on the “dotted line” in IEEE C57.109-1993 – IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration, Clause 4.4, Figure 4. The requirement for fault protection has been moved to a separate part of criterion 10 to clarify it applies only to load responsive transformer fault protection relays, and only when such relays are used.</td></tr>
<tr><td>Edward P. Cox</td><td>AEP Marketing</td><td>6</td><td rowspan="4">Negative</td><td rowspan="4">The following comments are a subset of those submitted during the comment period. For more comprehensive commentary, please see the comments provided during the comment period.

1. R1's Criterion 10: American Electric Power sees two issues with R1's Criterion 10. First, transformer "mechanical withstand capability" is undefined, vague, and subject to various interpretations. The terminology used in this criterion must be more tightly defined to prevent ambiguity or else referenced to some agreed-upon standard such as IEEE C57.109-1993. Second, American Electric Power agrees that it is appropriate for the 150% and 115% settings criteria to apply to line relays terminated only with a transformer. However, Criterion 10 seems to assume that transmission line relays on transmission lines terminated with a transformer are also typically intended to protect the transformer. This is not normally or necessarily true. If the line relays are not intended to protect the transformer and as long as the transformer relaying properly protects the transformer from mechanical damage, there is no reason for Criterion 10 to apply to the line relays. To address these two deficiencies in Criterion 10, American Electric Power is providing proposed replacement language as part of its comments submission.

2. Sections 4.2.3, 4.2.6, 6.2, and the applicability portion of Attachment B: The wording</td></tr>
<tr><td>Brock Ondayko</td><td>AEP Service Corp.</td><td>5</td></tr>
<tr><td>Paul B. Johnson</td><td>American Electric Power</td><td>1</td></tr>
<tr><td>Raj Rana</td><td>American Electric Power</td><td>3</td></tr>
</table>

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

				under Sections 4.2.3, 4.2.6, 6.2, and the applicability portion of Attachment B needs to be made consistent to avoid any misinterpretations and confusion. American Electric Power is providing proposed replacement language as part of its comments submission. 3. Requirement 7: Need to provide a 60-month timeline to implement the noted requirements for each facility that is added to the Planning Coordinator's initial list of facilities that must comply with this standard, versus the 24-month timeline to implement the noted requirements for each facility that is added to the Planning Coordinator's established list of facilities that must comply with this standard. This is a practical consideration that recognizes the high likelihood that the number of facilities that will be identified during development of the initial list of facilities will be many times greater than the incremental number of facilities that will be identified during the annual assessments and added to the established list of facilities. In addition, need to specify under this requirement whether any facilities that drop off the Planning Coordinator's list of facilities while still within the applicable (60-month or 24-month) implementation timeline must still comply with this standard. 4. Attachment A, Section 1.6: The wording of Attachment A, section 1.6 needs to be made consistent to avoid any confusion. American Electric Power is providing proposed replacement language as part of its comments submission. 5. Attachment B: Need to include a review and appeals process as part of the annual assessment for the Planning Coordinator to review the proposed facilities with the transmission entity prior to adding those facilities to the Planning Coordinator's list of facilities that must comply with the standard. American Electric Power is providing proposed replacement language as part of its comments submission.

Response: Thank you for your comments

1. The mechanical withstand is defined in IEEE C57.109-1993, *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, and a reference to this standard has been added as a footnote to address your concerns. The drafting team has modified the text of the standard to make the consideration of the mechanical withstand capability applicable to only the load responsive transformer fault protection relays, and only when such relays are used.
2. The drafting team agrees that inconsistency between these sections of the standard will lead to confusion. The drafting team has removed parts 6.1 and 6.2 from Requirement R6 to avoid redundancy, and has revised the Applicability section and Attachment B based on industry comments to provide consistency and clarity.
3. The drafting team has considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1.

4. Section 1.6 has been modified essentially as is suggested in the comment.
5. The drafting team has added to some of the criteria that the Planning Coordinator shall consult with the Facility owner when performing its assessment to provide the Facility owner an opportunity for input into the assessment. Additionally, an appeals process will be included in the NERC Rules of Procedure so that a Facility owner may appeal a decision in the event it believes a circuit is incorrectly identified by the Planning Coordinator.

Kirit S. Shah	Ameren Services	1	Negative	(1) Requirements R4 and R5 are already covered in Stanadrds FAC-008 and FAC-009. So they are redundant here and should be removed. (2) Section 6.2 is unclear and seems arbitrary in the statement 'if the Regional Entity has indentified either of these Element types as critical facilities for the purpose of the Compliance registry'. A clear test is lacking. (3) Section 1.6 is contrary to section 2.0 and seems arbitrary. Why is a communication system for a current-based scheme treated to a higher standard than other communications scheme? The communications scheme reliability is covered through the maintenance and misoperations analysis standards. (4) Criterion B1, which has been modified to encompass only flowgates which have been included to address long-term reliability concerns, while a step in the right direction, does not go far enough. Because flowgates are primarily utilized to manage congestion and assist in the process of transmission service sales, rather than investigate reliability issues more appropriately conducted via study work covered under the TPL standards, this criteria should be eliminated. (5) Criterion B4 as worded still exceeds the requirements of Reliability Standard TPL-003 by requiring simulating double contingencies with no operator intervention permitted. While such simulation would be done as part of assessment work under TPL-003 for fast-acting contingencies involving multiple circuits, such as Category C1 bus faults, C2 breaker failures, and C5 double-circuit tower outages, such simulations are not necessary under TPL-003 with Category C3 events which consist of separate Category B events with intervening operator action. Such simulations should not be made necessary as part of the proposed PRC-023-2 standard. Rather, should the TPL-003 performance requirements not be met for Category C3 contingencies with operator intervention considered, those facilities could be included in the list of facilities specified in PRC-023-2 Requirement R6.
Mark Peters	Ameren Services	3		

Response: Thank you for your comments.

1. Providing this information to the specified entities addresses the potential for confusion as to the amount of time available to take corrective action. FAC-008 and FAC-009 do not address this issue. FAC-009 requires transmitting the Facility Rating, whereas PRC-023-2 requires notification when the relay loadability is based on a 15-minute rating.
2. The drafting team has removed parts 6.1 and 6.2 from Requirement R6 to avoid redundancy, and has revised the Applicability section and Attachment B (which used the same phrase) based on industry comments to provide clarity. The drafting team has replaced the phrase "critical for the purposes of the Compliance Registry" with text from ¶60 of Order No. 733, which references text in section III.d.2 of the NERC Statement of Compliance Registry Criteria. So the second category of circuits to be evaluated now refers to transmission lines and transformers operated below 100 kV "that are included on a critical facilities list defined by the Regional Entity." The test by which the Regional Entity may make this determination is outside the scope of this standard.
3. Current-differential telecommunications systems are different than other telecommunications systems, in that the sensitivities for the protection elements are often set very sensitively – well below load current – and depend on the integrity of the channel to make a trip/no trip decision where other telecommunication system technologies require the operation of other protection system elements (usually distance elements) which are already subject to the requirements of this standard. Therefore, they will trip immediately due to load current upon the loss of communications, and are dependent on the fault detectors to inhibit trip.
4. Congestion and system reliability are not mutually exclusive concerns. The Interchange Distribution Calculator (IDC) was developed to address reliability concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. The IDC is intended to identify and unload critical circuits that could become overloaded due to transactions. While Flowgates and the IDC are used to manage congestion, the underlying basis for doing so is to preserve system reliability.

   The Flowgate Methodology defines that Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. If monitored Facilities of flowgates do not meet the Relay Loadability requirements in PRC-023, violation of physical system limitations could occur, leading to instability, uncontrolled separation, or cascading outages. As such, it is appropriate and necessary to include monitored Facilities of flowgates as applicable circuits under PRC-023-2.

   The drafting team acknowledges that Planning Coordinators do not decide which flowgates are included in the IDC; however, the NERC Functional Model does indicate that Planning Coordinators are responsible for coordinating transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators. Thus it is appropriate that Planning Coordinators, in applying the criteria in Appendix B, provide a screening as to whether the monitored Facilities of a flowgate are added to the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2.

   Based on a number of comments, the drafting team has modified criterion B1 to refer to "permanent" flowgates and has replaced the reference to "long-term reliability concerns" with "reliability concerns for loading of that circuit." The drafting team believes this more clearly reflects the intent to exclude flowgates that are established on a temporary basis and more clearly identifies the role of the Planning Coordinator in applying criterion B1.
5. The drafting team received several comments regarding "going beyond" TPL requirements by not simulating manual system adjustment in between contingencies. The purpose of this criterion is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. As such, criterion B4 does not require that all double contingency combinations be tested. It also does not require that the loadings respect the published applicable ratings of the circuits. It does require that engineering judgment be used to select certain combinations of line outages to be studied without manual system adjustment to ensure that, if the manual adjustments were not completed before the second contingency, the relay settings on the lines remaining in service would not inappropriately trip the lines

Jason Shaver	American Transmission Company, LLC	1	Affirmative	Requirement R7 requires the Registered Entities to implement Requirement R1, Requirement R2, Requirement R3, Requirement R4, and Requirement R5 for each facility that the Planning Coordinator added to the list of facilities that must comply with this standard (per Requirement R6) by certain dates following notification by the Planning Coordinator. ATC believes it is difficult to determine without knowing the full scope of work. Until the Planning criteria can be determined, the scope is unknown. Assuming not many assets are added, two years would be a more reasonable amount of time.
Response: Thank you for your comments. The drafting team has considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1.				
Donald S. Watkins	Bonneville Power Administration	1	Negative	Please refer to formal BPA comments submitted for the period ending 12/16/10
Rebecca Berdahl	Bonneville Power Administration	3	Negative	Please refer to formal BPA comments submitted for period ending 12/16/10
Francis J. Halpin	Bonneville Power Administration	5	Negative	Please refer to BPA's formal comments submitted separately.
Brenda S. Anderson	Bonneville Power Administration	6	Negative	Please refer to formal BPA comments submitted for this comment period.
Response: Thank you for your comments. Please refer to the drafting team responses in the Consideration of Comments document.				
Gregory Van Pelt	California ISO	2	Negative	With regard to the questions asked in the comment form, the CAISO answers and comments are: Q1 - Yes Q2 - No comment from the PC perspective. The TOs are responsible for designing phase protection schemes appropriate to their systems. Q3 - No comment from the PC perspective. The facility owners are responsible Q4 - No comment from the PC perspective. The facility owners are responsible Q5 - No Comments: Wording for R 6.2 needs more clarity. Currently, only identifies the Regional Entity as identifying critical facilities. Believe it should also include the Planning Coordinator as an entity that may identify critical facilities operated below 100 kV. It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV that are part of the Bulk Electric System. This information is not readily available and there is no requirement for the Regional Entity to communicate this information to

				the Planning Coordinator. The concern is that inaction by the Regional Entity could cause the Planning Coordinator to be out of compliance with this requirement. Additional clarity is needed throughout requirement R6 and throughout the PRC-023-2 Standard. Q6 - No Comments: This requirement could be construed as potential for double jeopardy because failure to comply with Requirements 1-5 represent a violation of both Requirement 7 and Requirement 1-5. Q7 - Yes Q8 - No Comments: Additional clarity is needed in Attachment B and throughout the PRC-023-2 Standard.

Response: Thank you for your comments

Q1. Thank you for your comment

Q2. Thank you for your comment

Q3. Thank you for your comment

Q4. Thank you for your comment

Q5. The drafting team has removed parts 6.1 and 6.2 from Requirement R6 to avoid redundancy with the Applicability section and Attachment B. Within the Applicability section and Attachment B, a number of modifications have been made based on industry comments to improve clarity. The drafting team has replaced the phrase “critical for the purposes of the Compliance Registry” with text from ¶60 of Order No. 733, which references text in section III.d.2 of the NERC Statement of Compliance Registry Criteria, So the second category of circuits to be evaluated now refers to transmission lines and transformers operated below 100 kV “that are included on a critical facilities list defined by the Regional Entity.” The drafting team believes it is necessary to maintain consistency with the NERC Statement of Compliance Registry Criteria for the Regional Entity to develop a critical facilities list, and then have the Planning Coordinator apply the criteria in Attachment B to determine for which of the circuits on the list the applicable entities must comply with the standard. While the drafting team acknowledges there is no requirement for the Regional Entity to provide the list, the drafting team believes the Regional Entity will make a critical facilities list available as it is necessary for other entities to have this information to support reliable operation of the interconnected transmission grid.,

Q6. The drafting team understands the double jeopardy concern and has deleted Requirement R7. The Effective Dates section has been modified to address the timeline in which Facility owners must comply with Requirements R1 and R5 when the Planning Coordinator identifies a circuit for which the Facility owner must comply with the standard.

Q7. Thank you for your comment

Q8. Extensive revisions were made to Attachment B and throughout the standard to improve clarity.

Paul Rocha	CenterPoint Energy	1	Negative	CenterPoint Energy has several concerns with this proposed Standard. CenterPoint Energy's main concern is with the criteria in Attachment B used to determine which facilities must comply. 1. We do not agree with criterion B4 that a percent loading is a technically sound basis to indicate if a facility is operationally significant. CenterPoint Energy recommends the threshold be revised to apply to those facilities that the loss of which would risk cascading outages or voltage collapse. 2. Criterion B3 indicates any path that is used to supply off-site power to nuclear plants, as agreed to by the plant owner and the Transmission Entity. If the purpose of attachment B is to provide "bright line" criteria, then a negotiated agreement would not qualify as "bright line". Additionally, off-site power requirements are meant to ensure safe shutdown of nuclear reactors in a system restoration event where transmission lines are lightly loaded. CenterPoint Energy recommends it be deleted. 3. CenterPoint Energy recommends criterion B5 be deleted, as it is too broad and gives the PC too much discretion in determining other facilities which must comply with this Standard. In addition, CenterPoint Energy believes Transmission Planners should have a role in the determination of which facilities must comply with this standard. 4. The use of the term "critical" in R6 is problematic, as it can cause confusion with NERC CIP Standards which require the facility owner to determine Critical Assets. CenterPoint Energy recommends using "operationally significant" wherever "critical" is used.

Response: Thank you for your comments.

1. The purpose of the criteria in Attachment B is to identify circuits that present a risk of cascading outages if relay loadability requirements are not met. Applying criterion B4 only to circuits for which their loss would risk cascading outages or voltage collapse would create circularity in the assessment by requiring the Planning Coordinator to know the outcome before applying the criteria.
2. In response to comments on criterion B3 the drafting team has modified the criterion to refer explicitly to "the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001." The drafting team believes this modification to criterion B3 provides a level of measurability that should address the commenter's concern.
3. The drafting team has modified criterion B5 in response to industry comments to require that if the Planning Coordinator selects a circuit based on technical studies or assessments, other than those specified in criteria B1 through B4, that such selection is to be made in consultation with the Facility owner to provide the Facility owner an opportunity for input into the assessment. Additionally, an appeals process will be included in the NERC Rules of Procedure so that a Facility owner may appeal a decision in the event it believes a circuit is incorrectly identified by the Planning Coordinator. The drafting team believes

				the Planning Coordinator is the NERC Functional Model entity with the wide-area view and study expertise necessary to perform the assessment in Attachment B. The drafting team also notes that assigning this responsibility solely to the Planning Coordinator is consistent with the approved PRC-023-1 and FERC Order No. 733. 4. The context in which the term "critical" is used is different than in the NERC "Zone 3" and "Beyond Zone 3" reviews. The remaining references to the term critical are in the context of NERC Statement of Compliance Registry Criteria. Rather than using the term "operationally significant," the drafting team has replaced the phrase "critical for the purposes of the Compliance Registry" with text from ¶60 of Order No. 733, which references text in section III.d.2 of the NERC Statement of Compliance Registry Criteria, so the second category of circuits to be evaluated now refers to transmission lines and transformers operated below 100 kV "that are included on a critical facilities list defined by the Regional Entity." The drafting team made corresponding modifications to the Applicability section.
Shamus J Gamache	Central Lincoln PUD	4	Negative	Central Lincoln supports the Pacific Northwest Small Public Power Group comments: 1. The comment group finds R1.10 very confusing when attempting to understand it in the context of IEEE C57.109-1993. C57.109 identifies a solid curve as the thermal damage curve, while a dotted dog leg is the mechanical damage curve. Generally the dog leg is only considered for those class II and III transformers subjected to frequent through faults and all class IV transformers. Is the intent of the SDT to require this level of protection for all transformers regardless of through fault frequency and/or transformer class? If the SDT really meant to protect transformers from thermal or combination damage, please note that it is not possible to completely protect transformers from the thermal damage of low current long duration faults while still complying with the 150% of maximum rating. The thermal damage curve extends down to twice the base current. A footnote in C57.109 states that base current is established from the lowest nameplate kVA rating. A typical transformer with two stages of cooling will have a high nameplate rating of 1.67 times this base rating. The first bullet of R1.10 states affected entities must allow 1.5 times the maximum, so we are up to 2.5 times the base rating. Since we must allow this much without tripping, the relay must be set even higher. 1.2 times would be a secure margin, so the relay is set to pickup at 3 times the base rating. This setting would of course violate the first part of R1 criterion 10 because the transformer's fault capability would be exceeded for faults between 2 and 3 times the base rating. 2. We also note that criterion 11 is apparently an exception to criterion 10, but this is not altogether clear since 10 is for fault protection while 11 is for overload protection. Please rewrite this (these) criterion (criteria) to clarify the SDT's intent(s). 3. We thank the SDT for addressing our concern regarding radially operated circuits. We

				note, however, that the key word “operated” from the consideration of comments was dropped before it reached the standard. Please change the last bullet of B4 to: Radially operated circuits serving only load are excluded.
Response: Thank you for your comments. 1. The drafting team has clarified this requirement by making it a separate part of criterion 10 and by indicating this criterion applies to load responsive transformer fault protective relays, if used. A footnote has been added to criterion 10 to clarify this requirement is based on the “dotted line” in IEEE C57.109-1993 – *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4. The drafting team notes that 150 percent of a typical maximum transformer nameplate rating is on the order of 250 percent (150 percent x 1.67) of the base nameplate rating. The vertical portion of the mechanical withstand curve is defined by 1/(2xZt), which for a transformer with 12 percent impedance is approximately 400 percent of the nameplate base rating, allowing protection to be set above the loadability requirement in criterion 10 and below the transformer mechanical withstand curve 2. Criterion 10 and Criterion 11 are meant to address separate applications. Criterion 10 addresses fault protection relays and their response to load; Criterion 11 explicitly addresses thermal overload protection. 3. The drafting team agrees with your comment and has modified criterion B4 accordingly.				
Timothy Beyrle	City of New Smyrna Beach Utilities Commission	4	Affirmative	• R1 and R2 have binary VSLs where they should be percentages of all relays that need to meet the standard based on statistical sampling.
Response: Thank you for your comments. The VSLs defined are consistent with the VSLs already approved by FERC in PRC-023-1.				
Chang G Choi	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	1	Negative	1. Transmission or Transformers that normally would not be considered BES assets are subject to inclusion by the Planning Coordinator. The criteria for inclusion have not been developed yet.

<table>
<tr><td>Max Emrick</td><td>City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power</td><td>5</td><td></td><td>2. Attachment A Section 1.6 was added due to FERC Order 733, but it is still vague what includes “Supervisory Elements”. Please clarify supervisory elements (Does it include RTUs?)

3. Detailed direction about relay setting methodology could be expanded to 110-kV level by this revision. Much more research should be devoted to such detailed changes to evaluate impact to other protection and operation constraints, before such settings are mandatory.

4. The new requirement (R2) may present conflicting choices for a relay engineer, since out-of-step blocking is technically challenging to set, sense and discriminate from certain loading and fault conditions.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.
1. The NERC Statement of Compliance Registry Criteria permits application of NERC Reliability Standards to certain facilities operated below 100 kV, such as for transmission elements operated below 100 kV that are included on a critical facilities list defined by the Regional Entity. The test by which the Regional Entity may make this determination is outside the scope of this standard. The criteria by which the Planning Coordinators determine for which of the circuits on the list the applicable entities must comply with the standard are defined in Attachment B.
2. Attachment A, Section 1.6 has been modified to include supervisory elements only as they apply to current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications. The drafting team believes this modification provides clarity that this section does not apply to RTUs and other applications.
3. The drafting team understands your concern and will place this item in the issues database for future consideration in the next general revision of the standard. However, the drafting team notes that PRC-023-1 already applies to lines operated at 100 kV to 200 kV and the drafting team does not believe that a significant number of sub-100 kV circuits will be impacted. As such, the drafting team disagrees that more research is required prior to implementing PRC-023-2.
4. The drafting team notes that Requirement R2 does not add a new obligation on Transmission Owners, Generator Owners, and Distribution Providers; it only explicitly states in PRC-023-2 an obligation that presently is included in Attachment A, Section 2 of PRC-023-1.</td></tr>
<tr><td>Randall McCamish</td><td>City of Vero Beach</td><td>1</td><td>Affirmative</td><td>R1 and R2 have binary VSLs where they should be percentages of all relays that need to meet the standard based on statistical sampling.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.
The VSLs defined are consistent with the VSLs already approved by FERC in PRC-023-1.</td></tr>
<tr><td>Michelle A Corley</td><td>Cleco Corporation</td><td>3</td><td rowspan="3">Negative</td><td rowspan="3">Cleco respectfully disagrees with NERC by establishing a Standard which mandates how we should set protective relays. It is our intention to establish relay settings which safely protect the public and facilities. If prudent engineering practice results in a relay becoming the limiting element within a facility, the facility rating should be adjusted as is specified in FAC-008. Relays should not be treated any different than other elements when rating a facility. If system studies show the facility is overloaded, then the utility can decide how best to increase the rating.</td></tr>
<tr><td>Stephanie Huffman</td><td>Cleco Power</td><td>5</td></tr>
<tr><td>Danny McDaniel</td><td>Cleco Power LLC</td><td>1</td></tr>
</table>

Robert Hirchak	Cleco Power LLC	6		
Response: Thank you for your response. Your comment is largely related to the existing approved PRC-023-1; this standard results from observations wherein protective relay loadability was heavily complicit with the 2003 blackout and numerous other major system disturbances, resulting in an acknowledged need to define appropriate criteria.				
Paul Morland	Colorado Springs Utilities	1	Negative	CSU provides the following comment: The documentation for PRC-023 seems to rely quite heavily on the usage of spread sheets and and calculations (with the possibility of having bad formulas). Some engineers who rely on graphical methods from coordination software may be less likely to have "bad formula" issues. There seems to be a bias in this standard to the formula based spreadsheet, where there is no mention of guidelines for those spreadsheets or a NERC provided spreadsheet.
Response: Thank you for your comment. It is left to each entity to determine how to implement the standard and document compliance. The Measures in the standard are only examples of the types of documentation that may be considered acceptable evidence.				
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Abstain	Criteria 10 under requirement 1 needs to be clarified so that the full implication is completely understood.
Response: Thank you for your comments. The text of the standard has been modified to clarify the intent of criterion 10. Specifically, a footnote has been added to criterion 10 to clarify that use of the phrase "mechanical withstand" is based on the "dotted line" in IEEE C57.109-1993 – *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4. The requirement for fault protection has been moved to a separate part of criterion 10 to clarify it applies only to load responsive transformer fault protection relays, and only when such relays are used.				
Christopher L de Graffenried	Consolidated Edison Co. of New York	1	Negative	1. R1 - Clarification is needed on whether criterion 10 requires a transformer to have load responsive protection to protect from mechanical damage. The wording in criterion 10 should be changed to "set transformer fault protection relay or transmission line relay on transmission line terminated with only a transformer." Is this criterion requiring that a transformer with only differential protection and no other load responsive remote protection be mitigated with additional load responsive protection? The loading on phase angle regulators, and series reactors should also be considered and mentioned. 2. Also, there appears to be words missing in criterion 9 of R1: "the maximum current flow from the ? to the ? under any system configuration."
Peter T Yost	Consolidated Edison Co. of New York	3		
Wilket (Jack) Ng	Consolidated Edison Co. of New York	5		

Nickesha P Carrol	Consolidated Edison Co. of New York	6		3. R2 - What is the expectation for verifying that the out-of-step (OOS) blocking elements allow tripping of phase protection relays for faults that occur during the loading conditions used to verify transmission line relay loadability? It would be costly and time consuming to verify this. To comply with this requirement, utilities may have to remove OOS protections all together. 4. Attachment B - Why does B3 only apply to Nuclear Power Plants only?
Response: Thank you for your comments. 1. The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point. 2. The text has been corrected. 3. The drafting team believes that this requirement will be met by a planning analysis of the settings. This is not a new requirement. PRC-023-1 requires that this analysis be done within Attachment A. 4. This criterion applies specifically to nuclear plants for the purpose of supporting nuclear plant safe operation and shutdown. The drafting team believes the added reference to the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001 better reflects this intent.				
David Frank Ronk	Consumers Energy	4	Negative	We have the following comment on the revisions, specifically sub-requirement R1.12a, which states, "Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.". We have no issue with this requirement on transmission lines that are 200 kV or greater. However, we do have a concern with applying requirement R1.12a on lower voltage lines now that the Transmission Relay Loadability Standard is being revised to included selected equipment 200 kV and below. The positive-sequence line angle on lower voltage lines, such as 69 kV or 46 kV, is significantly lower than 90 degrees. The positive-sequence line angle for 3/0 ACSR, for example, is only 55 degrees. Setting a 90 degree MTA on these lines would require a much larger reach setting to provide adequate line protection. In some cases, especially for lines with long spurs and poor line conductor, the increased reach setting may actually provide less loadability than a reach setting based on an MTA set at the positive-sequence line angle. A 90 degree MTA also dramatically reduces the resistive fault coverage for these lines. For these reasons, we would propose a modification to sub-requirement R1.12a as follows: Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer on 200 kV or greater transmission lines. Set the maximum torque angle (MTA) to the positive-sequence line angle on transmission lines less than 200 kV.
James B Lewis	Consumers Energy	5		
Response: Thank you for your comments. The drafting team understands your concern and will place this item in the issues database for future consideration in the next general revision of the standard.				

Russell A Noble	Cowlitz County PUD	3	Negative	1. The comment group that Cowlitz PUD coordinated comments with finds R1.10 very confusing when attempting to understand it in the context of IEEE C57.109-1993. C57.109 identifies a solid curve as the thermal damage curve, while a dotted dog leg is the mechanical damage curve. Generally the dog leg is only considered for those class II and III transformers subjected to frequent through faults and all class IV transformers. Is the intent of the SDT to require this level of protection for all transformers regardless of through fault frequency and/or transformer class? If the SDT really meant to protect transformers from thermal or combination damage, please note that it is not possible to completely protect transformers from the thermal damage of low current long duration faults while still complying with the 150% of maximum rating. The thermal damage curve extends down to twice the base current. A footnote in C57.109 states that base current is established from the lowest nameplate kVA rating. A typical transformer with two stages of cooling will have a high nameplate rating of 1.67 times this base rating. The first bullet of R1.10 states affected entities must allow 1.5 times the maximum, so we are up to 2.5 times the base rating. Since we must allow this much without tripping, the relay must be set even higher. 1.2 times would be a secure margin, so the relay is set to pickup at 3 times the base rating. This setting would of course violate the first part of R1 criterion 10 because the transformer's fault capability would be exceeded for faults between 2 and 3 times the base rating. 2. We also note that criterion 11 is apparently an exception to criterion 10, but this is not altogether clear since 10 is for fault protection while 11 is for overload protection. Please rewrite this (these) criterion (criteria) to clarify the SDT's intent(s). 3. We thank the SDT for addressing our concern regarding radially operated circuits. We note, however, that the key word "operated" from the consideration of comments was dropped before it reached the standard. Please change the last bullet of B4 to: Radially operated circuits serving only load are excluded.
Rick Syring	Cowlitz County PUD	4		
Bob Essex	Cowlitz County PUD	5		

Response: Thank you for your comments.

1. The drafting team has clarified this requirement by making it a separate part of criterion 10 and by indicating this criterion applies to load responsive transformer fault protective relays, if used. A footnote has been added to criterion 10 to clarify this requirement is based on the "dotted line" in IEEE C57.109-1993 – *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4. The drafting team notes that 150 percent of a typical maximum transformer nameplate rating is on the order of 250 percent (150 percent x 1.67) of the base nameplate rating. The vertical portion of the mechanical withstand curve is defined by 1/(2xZt), which for a transformer with 12 percent impedance is approximately 400 percent of the nameplate base rating, allowing protection to be set above the loadability requirement in criterion 10 and below the transformer mechanical

withstand curve. 2. Criterion 10 and Criterion 11 are meant to address separate applications. Criterion 10 addresses fault protection relays and their response to load; Criterion 11 explicitly addresses thermal overload protection. 3. The drafting team agrees with your comment and has modified criterion B4 accordingly.				
Michael F Gildea	Dominion Resources Services	3	Affirmative	5.1 Requirement R1. Dominion would like to see the exception of "switch on to fault" schemes added back in.
Response: Thank you for your comments. The drafting team understands the commenter's concern that the proposed implementation plan for PRC-023-2 had the unintended consequence of shortening the time provided for Facility owners to comply with Requirement R1 for switch-on-to-fault schemes. The drafting team has modified the effective dates in the standard to address this problem.				
Henry Ernst-Jr	Duke Energy Carolina	3	Negative	Duke Energy appreciates the work of the drafting team, but believes additional changes are needed before voting to approve PRC-023-2. 1. R6.1 and R6.2 unnecessarily duplicate the first part of Attachment B, and should be deleted from R6. 2. R6.3 and R6.4 are both associated with maintaining the list and should be combined into a separate requirement (new R7), with its own VRF and VSLs. Including the year for a facility should apply to all the criteria, not just B4. Suggested wording for new R7: "Maintain a list of circuits that must comply with this standard due to meeting Attachment B criteria. For each circuit, include the applicable criteria and the year studied for which the criteria first applies, when a facility is added to the list." 3. R6.5 should become a new R8 with its own VRF and VSLs. No wording changes needed. 4. Since the Attachment B criteria are applied beyond the operating horizon, R7 should be rewritten (and also renumbered as R9). Suggested wording: " Each Transmission Owner, Generator Owner, and Distribution Provider shall implement Requirement R1, Requirement R2, Requirement R3, Requirement R4, and Requirement R5 for each facility that is added to the Planning Coordinator's list of facilities that must comply with this standard pursuant to Requirement R6, by the first day of the first calendar quarter of the year in which Attachment B criteria first apply. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

<table>
<tr><td></td><td></td><td></td><td></td><td>5. B2 needs additional clarification, because identification could be in the short term or long term planning horizon. Suggested rewording: “B2. Each circuit that is a monitored Element of an IROL where the IROL was determined beyond the operating horizon.”

6. B3 needs additional clarification, to explicitly identify the necessary agreement between the plant owner and Transmission Entity. Suggested rewording: “Each circuit that forms a path (as agreed to by the plant owner and the Transmission Entity pursuant to NUC-001) to supply off-site power to nuclear plants.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.

1. R6.1 and R6.2 have been removed from PRC-023-2 in response to comments.
2. The drafting team believes that it is appropriate to include details regarding maintenance of the list as a part of Requirement R6 consistent with the existing standard PRC-023-1. While the drafting team disagrees that parts 6.3 and 6.4 should become a separate requirement, the drafting team has combined these into one part of Requirement R6 consistent with the commenter’s recommendation. The combined text, now part 6.1, reads:
“6.1 Maintain a list of circuits operated below 200kV and subject to the standard per application of Attachment B, which includes the first calendar year in which any criterion in Attachment B applies.”
3. The structure of the standard text within R6 including the approved VRFs and VSLs is similar to R3 in PRC-023-1, and therefore it is beyond the scope of the project to modify this structure.
4. The drafting team notes that Requirement R7 has been deleted in response to other comments. The Effective Dates section has been modified to address the timeframe in which Facility owners must comply with Requirements R1 through R5 when the Planning Coordinator identifies a circuit for which the Facility owner must comply with the standard.
5. In response to several comments on this subject, the drafting team has replaced the reference to “determined in the long-term planning horizon” with “determined in the planning horizon pursuant to FAC-010.”
6. In response to comments on criterion B3 the drafting team has modified the criterion to refer explicitly to “the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.”</td></tr>
<tr><td>Chuck B Manning</td><td>Electric Reliability Council of Texas, Inc.</td><td>2</td><td>Negative</td><td>ERCOT ISO has filed comments through the online form. Please reference filed comments for details.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.
Please refer to the drafting team responses in the Consideration of Comments document.</td></tr>
<tr><td>Robert Martinko</td><td>FirstEnergy Energy Delivery</td><td>1</td><td rowspan="3">Negative</td><td rowspan="3">Please see FirstEnergy's comments submitted separately through the comment period posting.</td></tr>
<tr><td>Kevin Querry</td><td>FirstEnergy Solutions</td><td>3</td></tr>
<tr><td>Mark S Travaglianti</td><td>FirstEnergy Solutions</td><td>6</td></tr>
</table>

Response: Thank you for your comments. Please refer to the drafting team responses in the Consideration of Comments document.				
Frank Gaffney	Florida Municipal Power Agency	4	Affirmative	R1 and R2 have binary VSLs where they should be percentages of all relays that need to meet the standard based on statistical sampling.
David Schumann	Florida Municipal Power Agency	5		
Richard L. Montgomery	Florida Municipal Power Agency	6		
Thomas W. Richards	Fort Pierce Utilities Authority	4		
Response: Thank you for your comments. The VSLs defined are consistent with the VSLs already approved by FERC in PRC-023-1.				
Ajay Garg	Hydro One Networks, Inc.	1	Negative	Hydro One is casting a negative vote with the following comments: PRC-023-2 addresses the Phase I directives from FERC Order 733 including a process for use in determining which facilities (transmission lines operated below 200 kV and transformers with low voltage terminals connected below 200 kV) must meet specific relay loadability criteria. Category B4 in the criteria is intended to identify 100 kV to 200 kV lines that will experience different degrees of thermal overload with respect to their Facility Rating for different loading duration. Since these durations may be as long as several hours, it is unreasonable to impose the restriction of “without manual system adjustment in between (the two contingencies)” on the B4 test procedure. Aside from this restriction, the degree of thermal overload with respect to Facility Rating (of various loading durations) is not a relevant measure of the significance of that overload for the reliability of the system. The correct measure is whether tripping of the overloaded line, either by manual operator action (along with other system adjustments that would be available during the relevant time period) or as a consequence of protection and control actions, would result in cascaded tripping of other bulk transmission lines.
David L Kiguel	Hydro One Networks, Inc.	3		
Response: Thank you for your comments. Circuits subject to loading in excess of their emergency rating are susceptible to tripping, which could lead to instability, uncontrolled separation, or cascading outages. The drafting team believes it is impractical to expect the Planning Coordinator to anticipate and assess every possible system situation that could lead to these conditions. Thus the criteria in Attachment B were selected to identify circuits that present a risk of cascading outages if relay loadability requirements are not met. The drafting team has added to some of the criteria that the Planning Coordinator is to consult with the Facility owner when performing its assessment to provide the Facility owner an opportunity for input into the assessment. Additionally, an appeals process will be included in the NERC Rules of Procedure so that a Facility owner may appeal a decision in the event it believes a circuit is incorrectly identified by the Planning Coordinator.				

Kim Warren	Independent Electricity System Operator	2	Negative	Clarification is needed on whether criterion 10 requires a transformer to have load responsive protection to protect from mechanical damage. The wording in criterion 10 should be changed to "set transformer fault protection relay or transmission line relay on transmission line terminated with only a transformer." Is this criteria requiring that a transformer with only differential protection and no other load responsive remote protection be mitigated with additional load responsive protection?
Response: Thank you for your comments. The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point.				
Michael Moltane	International Transmission Company Holdings Corp	1	Negative	ITC votes "Negative" on this ballot for the following reasons: R2: ITC is not clear that we can provide the documentation required to provide evidence that an OSB element will, with heavy load, allow tripping. Out of step relaying is based on a moving impedance locus for a swing versus a fault. Different relays will operate differently and in some relays there is a small period of time, 2 seconds, where heavy loads will block tripping. Is the requirement trying to say that the out of step blocking element must never pick up and block for unusually heavy loads or is there more to it? This requirement is too restrictive and does not allow for engineering judgment for out of step protection. The drafting team must provide guidance on how to meet this requirement? We are concerned that an unusually heavy load swing will appear to the correct OSB setting as a swing and prevent tripping for a short time. Setting OSB relays per the new R2 to allow tripping for these severe and highly improbable conditions may remove blocking for the actual predicted swings and have a worse effect on the BES. R7: When this new criteria goes into effect, circuits will become designated as "Critical" that were not before. There must be adequate time allowed for utilities to budget, engineer and construct new relay systems to meet this standard. Some medium voltage lines may need to be re-terminated and will require a significant amount of time to get planned and constructed. We suggest an implementation time of 36 months after identification by the planning coordinator.
Response: Thank you for your comment. R2: The drafting team notes that Requirement R2 does not add a new obligation on Transmission Owners, Generator Owners, and Distribution Providers; it only explicitly states in PRC-023-2 an obligation that presently is included in Attachment A, Section 2 of PRC-023-1. R7: The drafting team has considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1.				

Kathleen Goodman	ISO New England, Inc.	2	Negative	ISO New England is voting no for the following reasons: B2. Item B2 adds significant confusion to the process. The long term planning horizon may include transmission projects which have not even been built or alternative system configurations which do not exist, making it impossible for affected parties to set their relays appropriately. Suggested replacement language to avoid this issue: “Each circuit that is a monitored element of an IROL, assuming that all transmission elements are in service and the system is under normal conditions.” B3. This item indicates that the circuits to be considered are to be agreed to by the plant owner and the Transmission Entity. Attachment B is applicable to the Planning Coordinator. If this item is by agreement by the plant and the Transmission Entity it should be removed from Attachment B and placed elsewhere in the document. If this is intended to apply to the Planning Coordinator, Transmission Entity should be replaced with Planning Coordinator. Why does B3 only apply to Nuclear Power Plants? B4. This criterion is overly stringent and should be deleted. The system is neither planned nor operated to allow for two overlapping outages without operator action in between. If this criterion is retained, it should be made consistent with the requirements of TPL-003 where operator actions can be assumed between the first and second contingencies. Since a similar comment was made previously, more information is being provided following. 1. Since the system is neither planned nor operated to two overlapping outages in between, such testing may result in unsolved cases, or voltages well below criteria. In the case of an unsolved case, there are no flows to evaluate, making this standard impossible to apply. In the case of a solved case with voltages well below criteria, currents are likely to be incredibly high and therefore viewed as unrealistic. These concerns may limit the contingency selection to those which are not severe, eliminating any perceived benefit from this testing. 2. There is no guidance provided on how the system should be dispatched in the model upon which the overlapping contingencies are tested. This will result in significant discrepancies between the base assumptions used by the various Planning Coordinators. The contents of this standard should be reviewed to reflect the new definition of the Bulk Electric System.
Response: Thank you for your comments.				

<table>
<tr><td colspan="5">B2: In response to several comments on this subject the drafting team has replaced the reference to “determined in the long-term planning horizon” with “determined in the planning horizon pursuant to FAC-010.”

B3: This criterion applies to the Planning Coordinator and requires that the Planning Coordinator include circuits that form a path “(as agreed to by the plant owner 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” on the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2.
This criterion applies specifically to nuclear plants for the purpose of supporting nuclear plant safe operation and shutdown. The drafting team believes the added reference to the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001 better reflects this intent.

B4: The drafting team received several comments regarding “going beyond” TPL requirements by not simulating manual system adjustment in between contingencies. The purpose of this criterion is not to assess whether the system performance meets the TPL standard, rather, it is to be used as a screen to determine whether the relay loadability settings are properly set such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. As such, B4 does not require that all double contingency combinations be tested. It also does not require that the loadings respect the published applicable ratings of the circuits. It does require that engineering judgment be used to select certain combinations of line outages to be studied without manual system adjustment to ensure that, if the manual adjustments were not completed before the second contingency, the relay settings on the lines remaining in service would not inappropriately trip the lines. This standard, like all others, will need to be reviewed when a new definition of the Bulk Electric System is approved.</td></tr>
<tr><td>Michael Gammon</td><td>Kansas City Power & Light Co.</td><td>1</td><td rowspan="3">Negative</td><td rowspan="3">Attachment B is duplicative to the criteria established in the TPL planning standards and can be conflicting regarding the identification of critical circuits by Planning Authorities and Transmission Planners. Removal of Attachment B is recommended and replace with language that specifies facilities 100kv and above identified by Planning Authority or by the Transmission Planner are applicable to the Standard.</td></tr>
<tr><td>Charles Locke</td><td>Kansas City Power & Light Co.</td><td>3</td></tr>
<tr><td>Jessica L Klinghoffer</td><td>Kansas City Power & Light Co.</td><td>6</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.

Attachment B is not duplicative of the criteria established in the TPL planning standards, nor does it conflict with any responsibilities of Planning Coordinators (formerly Planning Authorities) or Transmission Planners. The purpose of the criteria in Attachment B is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. The introductory sentence in Attachment B has been revised to clarify the implication of identifying circuits per all criteria in the attachment: “If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.” These criteria provide a consistent methodology for Planning Coordinators to perform the determination presently assigned in Requirement R3 of PRC-023-1 (now Requirement R6 in PRC-023-2). This requirement supports the reliability purpose of this standard by identifying the circuits below 200 kV which could lead to cascading outages, if Protection Systems are not set according to the relay loadability requirements.</td></tr>
<tr><td>Stan T. Rzad</td><td>Keys Energy Services</td><td>1</td><td rowspan="2">Affirmative</td><td rowspan="2">R1 and R2 have binary VSLs where they should be percentages of all relays that need to meet the standard based on statistical sampling. But that doesn't seem to be that big a deal</td></tr>
<tr><td>Walt Gill</td><td>Lake Worth Utilities</td><td>1</td></tr>
</table>

Response: Thank you for your comments. The VSLs defined are consistent with the VSLs already approved by FERC in PRC-023-1.				
Joe D Petaski	Manitoba Hydro	1	Negative	Please see comments submitted by Manitoba Hydro in the formal comment period.
Greg C. Parent	Manitoba Hydro	3		
S N Fernando	Manitoba Hydro	5		
Daniel Prowse	Manitoba Hydro	6		
Response: Thank you for your comments. Please refer to the drafting team responses in the Consideration of Comments document.				
Terry Harbour	MidAmerican Energy Co.	1	Negative	1) The Attachment B criteria for determining what circuits must follow PRC-023 according to FERC Order 733 and paragraph 69 specifying tests to determine what facilities are "critical" to BES reliability are wrong and go beyond the FERC directive. There is no technical basis for including flowgates as an appropriate measure of an item that is critical to reliability. A flowgate is a point of market congestion that may or may not have an important reliability impact. Because a "flowgate" may not have a reliability impact any larger than any other transmission line, Appendix B criterion B1 should be dropped. If the standard drafting team wishes to keep criteria B1 it should prove there is a sound and measureable method to show a flowgate is critical to the operation of the BES and the loss of such a facility would result in instability, uncontrolled separation, and cascading. 2) References to Planning Coordinators and Regional Entities in sections 4.2.2, 4.2.3, 4.2.6, R6, and Attachment B should be eliminated or replaced with Transmission Owner and Transmission Operators. Transmission Owners and Operators understand what facilities are critical to the operation of the BES and should determine what is and is not critical to the BES based upon FPA Section 215 criteria, IROLs, and TPL standards.
Response: Thank you for your comments. 1) Congestion and system reliability are not mutually exclusive concerns. The Interchange Distribution Calculator (IDC) was developed to address reliability concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. The IDC is intended to identify and unload critical circuits that could become overloaded due to transactions. While Flowgates and the IDC are used to manage congestion, the underlying basis for doing so is to preserve system reliability. The Flowgate Methodology defines that Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. If monitored Facilities of flowgates do not meet the Relay Loadability requirements in PRC-023, violation of physical system limitations could occur, leading to instability, uncontrolled separation, or cascading outages. As such, it is appropriate and necessary to include monitored Facilities of flowgates as				

applicable circuits under PRC-023-2. The drafting team acknowledges that Planning Coordinators do not decide which flowgates are included in the IDC; however, the NERC Functional Model does indicate that Planning Coordinators are responsible for coordinating transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators. Thus it is appropriate that Planning Coordinators, in applying the criteria in Appendix B, provide a screening as to whether the monitored Facilities of a flowgate are added to the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2. Based on a number of comments, the drafting team has modified criterion B1 to refer to "permanent" flowgates and has replaced the reference to "long-term reliability concerns" with "reliability concerns for loading of that circuit." The drafting team believes this more clearly reflects the intent to exclude flowgates that are established on a temporary basis and more clearly identifies the role of the Planning Coordinator in applying criterion B1. 2) The Planning Coordinator is the NERC Functional Model entity with the wide-area view and study expertise necessary to perform the assessment in Attachment B. The drafting team also notes that assigning this responsibility to the Planning Coordinator is consistent with the approved PRC-023-1 and FERC Order No. 733.				
Thomas C. Mielnik	MidAmerican Energy Co.	3	Negative	1) The Attachment B criteria for determining what circuits must follow PRC-023 criteria according to the FERC Order 733 and paragraph 69 specifying tests to determine what facilities are "critical" to BES reliability is wrong and goes beyond the FERC directive. There is no technical basis for including flowgates as an appropriate measure of an item that is critical to reliability. A flowgate is a point of market congestion that may or may not have a important reliability impact. Because a "flowgate" may not have a reliability impact any larger than any other transmission line, Appendix B criterion B1 should be dropped. If the standard drafting team wishes to keep criteria B1 it should prove that there is a sound and measureable method to prove that a flowgate is critical to the operation of the BES and the loss of such a facility would result in instability, uncontrolled separation, and cascading. 2) References to Planning Coordinators and Regional Entities in sections 4.2.2, 4.2.3, 4.2.6, R6, and Attachment B should be eliminated or replaced with Transmission Owner and Transmission Operators. These entities understand what facilities are critical to the operation of the BES and should determine what is and is not critical to the BES based upon FPA Section 215 criteria, IROLs, and TPL standards.
Response: Thank you for your comments. 1) Congestion and system reliability are not mutually exclusive concerns. The Interchange Distribution Calculator (IDC) was developed to address reliability concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. The IDC is intended to identify and unload critical circuits that could become overloaded due				

to transactions. While Flowgates and the IDC are used to manage congestion, the underlying basis for doing so is to preserve system reliability. The Flowgate Methodology defines that Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. If monitored Facilities of flowgates do not meet the Relay Loadability requirements in PRC-023, violation of physical system limitations could occur, leading to instability, uncontrolled separation, or cascading outages. As such, it is appropriate and necessary to include monitored Facilities of flowgates as applicable circuits under PRC-023-2. The drafting team acknowledges that Planning Coordinators do not decide which flowgates are included in the IDC; however, the NERC Functional Model does indicate that Planning Coordinators are responsible for coordinating transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators. Thus it is appropriate that Planning Coordinators, in applying the criteria in Appendix B, provide a screening as to whether the monitored Facilities of a flowgate are added to the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2. Based on a number of comments, the drafting team has modified criterion B1 to refer to "permanent" flowgates and has replaced the reference to "long-term reliability concerns" with "reliability concerns for loading of that circuit." The drafting team believes this more clearly reflects the intent to exclude flowgates that are established on a temporary basis and more clearly identifies the role of the Planning Coordinator in applying criterion B1.

2) The Planning Coordinator is the NERC Functional Model entity with the wide-area view and study expertise necessary to perform the assessment in Attachment B. The drafting team also notes that assigning this responsibility to the Planning Coordinator is consistent with the approved PRC-023-1 and FERC Order No. 733.

Christopher Schneider	MidAmerican Energy Co.	5	Negative	1) The Attachment B criteria for determining what circuits must follow PRC-023 criteria according to the FERC Order 733 and paragraph 69 specifying tests to determine what facilities are "critical" to BES reliability is wrong and goes beyond the FERC directive. There is no technical basis for including flowgates as an appropriate measure of an item that is critical to reliability. A flowgate is a point of market congestion that may or may not have a important reliability impact. Because a "flowgate" may not have a reliability impact any larger than any other transmission line, Appendix B criterion B1 should be dropped. If the standard drafting team wishes to keep criteria B1 it should prove that there is a sound and measureable method to prove that a flowgate is critical to the operation of the BES and the loss of such a facility would result in instability, uncontrolled separation, and cascading. 2) References to Planning Coordinators and Regional Entities in sections 4.2.2, 4.2.3, 4.2.6, R6, and Attachment B should be eliminated or replaced with Transmission Owner and Transmission Operators. These entities understand what facilities are critical to the operation of the BES and should determine what is and is not critical to the BES based upon FPA Section 215 criteria, IROLs, and TPL standards.

Response: Thank you for your comments.

1) Congestion and system reliability are not mutually exclusive concerns. The Interchange Distribution Calculator (IDC) was developed to address reliability concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. The IDC is intended to identify and unload critical circuits that could become overloaded due

				to transactions. While Flowgates and the IDC are used to manage congestion, the underlying basis for doing so is to preserve system reliability. The Flowgate Methodology defines that Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. If monitored Facilities of flowgates do not meet the Relay Loadability requirements in PRC-023, violation of physical system limitations could occur, leading to instability, uncontrolled separation, or cascading outages. As such, it is appropriate and necessary to include monitored Facilities of flowgates as applicable circuits under PRC-023-2. The drafting team acknowledges that Planning Coordinators do not decide which flowgates are included in the IDC; however, the NERC Functional Model does indicate that Planning Coordinators are responsible for coordinating transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators. Thus it is appropriate that Planning Coordinators, in applying the criteria in Appendix B, provide a screening as to whether the monitored Facilities of a flowgate are added to the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2. Based on a number of comments, the drafting team has modified criterion B1 to refer to "permanent" flowgates and has replaced the reference to "long-term reliability concerns" with "reliability concerns for loading of that circuit." The drafting team believes this more clearly reflects the intent to exclude flowgates that are established on a temporary basis and more clearly identifies the role of the Planning Coordinator in applying criterion B1. 2) The Planning Coordinator is the NERC Functional Model entity with the wide-area view and study expertise necessary to perform the assessment in Attachment B. The drafting team also notes that assigning this responsibility to the Planning Coordinator is consistent with the approved PRC-023-1 and FERC Order No. 733.
Jason L Marshall	Midwest ISO, Inc.	2	Negative	1. While we appreciate the drafting team's effort to refine the flowgate criteria from the last posting, the modifications do not go far enough and still do not reflect the use of flowgates. NERC's definition of flowgate includes two components. Let's focus on the first component which represents those flowgates defined in the IDC. Because IDC flowgates list is updated monthly and the IDC users can add temporary flowgates to the IDC at any time, this is an inappropriate list to use. We appreciate the drafting team's attempt to resolve this issue by including the caveat "that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator." However, this really only confuses the matter and does not solve it. Reliability Coordinators add flowgates to manage real-time congestion. Planning Coordinators do not. Per the NERC functional model, they do not even have a role in deciding which flowgates to add to the IDC. Flowgates are added to the IDC to mitigate existing, known congestion points not congestion points identified in a long-term planning study that may never materialize due to changing conditions. Thus, IDC flowgates should be specifically excluded. Now let us focus on the second component of flowgate. The second component is much like the first component in that is it a mathematical construct to analyze the impact of power flows on the BES except is not required to be included in the IDC. There is nothing in the definition of a flowgate to give credence that is represents anything more than point to calculate power flows and the impact of transactions. Flowgates are primarily used to manage congestion on the system and to

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				sell transmission system. Because it is convenient to select a group of lines as a proxy to sell transmission service or manage congestion does not mean that those group of lines represent a reliability issue. Thus, we do not believe any flowgates should be included in the list. Any true reliability issues can be identified through the TPL studies and those facilities that do not meet the performance requirements are what should be used. 2. We do not support criterion B4. It exceeds what is required in the TPL standards and what is required per the reliability directive in Order 729. The TPL standards allow system operator intervention for category C3 contingencies between the two independent Category B contingencies. This standard should not exceed those requirements in the TPL standards. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test “must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning.” Paragraph 80 states that “the test must be consistent with the general reliability principles embedded in the existing series of TPL” standards. Thus, exceeding the TPL standards could be argued as deviating from the directive. In response to comments that did not support this criterion during the first posting, the standards drafting team responded with “Testing multiple element contingencies while accounting for system adjustments between each element outage will not yield any facilities to be subject to PRC-023 as long as TPL-003 system performance requirements are met.” We think the drafting team missed a basic point about the standard. The issue is not whether the registered entity develops and documents corrective action plans TPL-003-0a R2 and R3. The issue is if the system as currently designed meets the performance requirements in TPL-003-0a R1 which allows for operator interventions on Category C3 contingencies. For those C3 contingencies that don’t currently meet the performance obligations after operator interventions, the subject facilities would be included PRC-023-2 R6 list of facilities. 3. We do not believe this requirement R4 is needed. Limiting a relay setting to 115% of the associated transmission line’s highest seasonal 15 minute rating does not equate to a line that will trip before the operator has time to intervene. It does not mean the line will trip in 15 minutes. In fact, the operator should be taking action well in advance of reaching a 15 minute limit and the operator is likely only using the 15 minute rating in extreme circumstances.

				4. Furthermore, PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings including those limited by relays. As a result, neither PRC-023-2 R3 nor R4 is even needed. We assume the drafting team must be aware of these FAC standard requirements because they did not even require reporting to the Reliability Coordinator, Planning Coordinator and Transmission Operator of those circuits that are actually limited by the relay per criterion 12. We agree that FAC-008-1 and FAC-009-1 collectively establish the necessary requirements to compel the Transmission Owner and Generator Owner to communicate these relay limited circuits and that no additional requirements are necessary.

Response: Thank you for your comments.

1. Congestion and system reliability are not mutually exclusive concerns. The Interchange Distribution Calculator (IDC) was developed to address reliability concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. The IDC is intended to identify and unload critical circuits that could become overloaded due to transactions. While Flowgates and the IDC are used to manage congestion, the underlying basis for doing so is to preserve system reliability. The Flowgate Methodology defines that Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. If monitored Facilities of flowgates do not meet the Relay Loadability requirements in PRC-023, violation of physical system limitations could occur, leading to instability, uncontrolled separation, or cascading outages. As such, it is appropriate and necessary to include monitored Facilities of flowgates as applicable circuits under PRC-023-2. The drafting team acknowledges that Planning Coordinators do not decide which flowgates are included in the IDC; however, the NERC Functional Model does indicate that Planning Coordinators are responsible for coordinating transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators. Thus it is appropriate that Planning Coordinators, in applying the criteria in Appendix B, provide a screening as to whether the monitored Facilities of a flowgate are added to the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2. Based on a number of comments, the drafting team has modified criterion B1 to refer to “permanent” flowgates and has replaced the reference to “long-term reliability concerns” with “reliability concerns for loading of that circuit.” The drafting team believes this more clearly reflects the intent to exclude flowgates that are established on a temporary basis and more clearly identifies the role of the Planning Coordinator in applying criterion B1. FERC Order 733 has directed that this requirement be explicitly addressed within the requirements of PRC-023-2. FAC-008 and FAC-009 do not address this issue. FAC-009 requires transmitting the Facility Rating, whereas PRC-023-2 requires notification when the relay loadability is based on a 15-minute rating.

2. The drafting team received several comments regarding “going beyond” TPL requirements by not simulating manual system adjustment in between contingencies. The purpose of this criterion is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a

screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. As such, criterion B4 does not require that all double contingency combinations be tested. It also does not require that the loadings respect the published applicable ratings of the circuits. It does require that engineering judgment be used to select certain combinations of line outages to be studied without manual system adjustment to ensure that, if the manual adjustments were not completed before the second contingency, the relay settings on the lines remaining in service would not inappropriately trip the lines. 3. Providing this information to the specified entities addresses the potential for confusion as to the amount of time available to take corrective action. 4. FAC-008 and FAC-009 do not address this issue. FAC-009 requires transmitting the Facility Rating, whereas PRC-023-2 requires notification when the relay loadability is based on a 15-minute rating.				
Richard Burt	Minnkota Power Coop. Inc.	1	Negative	See comments submitted by MRO NSRS.
Response: Thank you for your comments. Please see the responses to comments submitted by MRO NSRS.				
Saurabh Saksena	National Grid	1	Negative	1. As per Section 4.2.3 (also included as bullet point 2 of Applicable circuits in Attachment B) "Transmission Lines operated below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry and the Planning Coordinator has determined are required to comply with this standard." National Grid believes that voltage levels less than 100 kV are outside NERC's jurisdiction and hence, requirements related to sub 100 kV levels should not be part of NERC standards. 2. National Grid recommends a provision in the standard which allows entities an option to 1. Either comply with standard for all applicable elements or 2. Apply the methodology as stated in Attachment B. The rationale is that entities that choose to comply with PRC-023 for all applicable elements should be recognized and should be exempted from complying with the methodology in Attachment B. 3. Requirement R6 of the proposed standard requires entities to apply criteria in Attachment B and conduct assessments with no more than 15 months between assessments to determine which transmission elements must comply with this standard. TPL standard which is considered to be the primary standard dealing with designing and planning of the system allows an interim assessment to rely on previous years simulations and does not mandate a stringent 15 month period between assessments. National Grid believes that an auxiliary PRC-023 standard should not present more stringent requirements than the primary TPL standard and recommends to remove the

				"15 month between assessments" requirement. 4. National Grid seeks clarification on whether criterion 10 requires transformer to have load responsive protection to protection from mechanical damage. The wording in criterion 10 should be changed to “set transformer fault protection relay or transmission line relay on transmission line terminated with only a transformer.” For example, is this criteria requiring that a transformer with only differential protection and no other load responsive remote protection be mitigated with additional load responsive protection?
Response: Thank you for your comments. 1) The drafting team understands the concern with including facilities operated below 100 kV; however, the NERC Statement of Compliance Registry Criteria does allow Regional Entities the ability to identify such facilities operated below 100 kV as required to comply with NERC Reliability Standards. The drafting team has replaced the phrase “critical for the purposes of the Compliance Registry” with text from the ¶60 of Order No. 733, which references text in section III.d.2 of the NERC Statement of Compliance Registry Criteria, so the second category of circuits to be evaluated now refers to transmission lines and transformers operated below 100 kV “that are included on a critical facilities list defined by the Regional Entity.” The drafting team made corresponding modifications to the Applicability section. 2) The drafting team has added a new criterion B6 to include any circuit mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner. Any circuit identified by criterion B6 would not require application of the other criteria in Attachment B. 3) The drafting team intended that an assessment be performed each year, but that the power flow analyses used to support the assessment need not be performed unless material changes to the system have occurred since the last assessment. The drafting team has added a footnote to criterion B4 to clarify this intent. 4) The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with Criterion 10 if it does exist. The standard has been modified to clarify this point.				
Randy MacDonald	New Brunswick Power Transmission Corporation	1	Negative	Criteria 10 under Requirement 1. The Criteria could subject the industry to adding phase overcurrent protection to a large number of transformers. Clarification is needed
Alden Briggs	New Brunswick System Operator	2	Negative	Criteria 10 under Requirement 1. The Criteria could subject the industry to unnecessarily adding phase overcurrent protection to a large number of transformers. Clarification is required.
Response: Thank you for your comments. The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point.				
Gregory Campoli	New York Independent	2	Negative	comments provided

	System Operator			
Response: Thank you for your comments. Please refer to the drafting team responses in the Consideration of Comments document.				
Gerald Mannarino	New York Power Authority	5	Negative	Comments to Question 1: ---------------------- 1. Clarification is needed on whether criterion 10 requires a transformer to have load responsive protection to protect from mechanical damage, either from internal faults, or through faults. If load responsive protection for the transformer element does not presently exist, i.e. only differential protection exists for the transformer element, will load responsive transformer protection have to be added to comply with this criterion? 2. The wording in criterion 10 should be changed to "Set transformer fault protection relays or transmission line relays on transmission lines terminated only with a transformer to ……." 3. Is this criteria requiring that a transformer with only differential protection and no other load responsive remote protection be supplemented with additional load responsive protection? 4. The loading on phase angle regulators, and series reactors should be considered and mentioned. 5. Also, there appears to be words missing in criterion 9 of R1: "the maximum current flow from the ? to the ? under any system configuration." From the NERC Webinar on 11/23/10 the intention was to address the possible locations where phase protection for the transformer could exist and not imply that this protection was needed at both locations. Comments to Question 8: ---------------------- 6. B2. Item B2 adds significant confusion to the process. The long term planning horizon may include transmission projects which have not even been built or alternative system configurations which do not exist, making it impossible for affected parties to set their relays appropriately. Suggested replacement language to avoid this issue: "Each circuit that is a monitored element of an IROL, assuming that all transmission elements are in service and the system is under normal conditions." 7. B3. This item indicates that the circuits to be considered are to be agreed to by the plant owner and the Transmission Entity. Attachment B is applicable to the Planning Coordinator. If this item is by agreement by the plant and the

				Transmission Entity it should be removed from Attachment B and placed elsewhere in the document. If this is intended to apply to the Planning Coordinator, Transmission Entity should be replaced with Planning Coordinator. Why does B3 only apply to Nuclear Power Plants? 8. B4. This criterion is overly stringent and should be deleted. The system is neither planned nor operated to allow for two overlapping outages without operator action in between. If this criterion is retained, it should be made consistent with the requirements of TPL-003 where operator actions can be assumed between the first and second contingencies. Since a similar comment was made previously, more information is being provided following. 1. Since the system is neither planned nor operated to two overlapping outages in between, such testing may result in unsolved cases, or voltages well below criteria. In the case of an unsolved case, there are no flows to evaluate, making this standard impossible to apply. In the case of a solved case with voltages well below criteria, currents are likely to be incredibly high and therefore viewed as unrealistic. These concerns may limit the contingency selection to those which are not severe, eliminating any perceived benefit from this testing. 2. There is no guidance provided on how the system should be dispatched in the model upon which the overlapping contingencies are tested. This will result in significant discrepancies between the base assumptions used by the various Planning Coordinators. The contents of this standard should be reviewed to reflect the new definition of the Bulk Electric System.

Response: Thank you for your comments.

1) The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point.

2) The drafting team has considered this comment and similar comments and has modified the text of the standard as appropriate.

3) The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point.

4) The drafting team believes that the phase angle regulating transformers are already included in the standard in Criteria 10 and 11, and that series reactors are already included as part of the element in which they are inserted. This comment will be considered as we prepare future versions of the standard.

5) The text of the standard has been corrected.

6) In response to several comments on this subject the drafting team has replaced the reference to "determined in the long-term planning horizon" with "determined in the planning horizon pursuant to FAC-010."

7) This criterion applies to the Planning Coordinator and requires that the Planning Coordinator include circuits that form a path "(as agreed to by the plant owner 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" on the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2. This criterion applies specifically to nuclear plants for the purpose of supporting nuclear plant safe operation and shutdown. The drafting team believes the added reference to the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001 better reflects this intent. 8) The drafting team received several comments regarding "going beyond" TPL requirements by not simulating manual system adjustment in between contingencies. The purpose of this criterion is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. As such, criterion B4 does not require that all double contingency combinations be tested. It also does not require that the loadings respect the published applicable ratings of the circuits. It does require that engineering judgment be used to select certain combinations of line outages to be studied without manual system adjustment to ensure that, if the manual adjustments were not completed before the second contingency, the relay settings on the lines remaining in service would not inappropriately trip the lines.				
Guy V. Zito	Northeast Power Coordinating Council, Inc.	10	Negative	Question has arisen during a technical evaluation of the NPCC membership regarding Criteria 10 under Requirement 1 of the draft standard. Would this requirement necessitate adding phase overcurrent protection to all transformers? Clarification is required for this Criteria before NPCC can support this standard so as to identify the implications of the adoption of such a requirement.
Response: Thank you for your comments. The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point.				
David H. Boguslawski	Northeast Utilities	1	Negative	Further clarification is needed for criterion 10 in R1. 1. Is it the intention of this criterion that all applicable transformers must have load responsive protection to prevent mechanical damage from a through fault? If load responsive protection for the transformer element does not presently exist, i.e. only differential protection exists for the transformer element, will load responsive transformer protection have to be added to comply with this criterion? 2. It is also suggested that R1 Criterion 10 wording be changed to "Set transformer fault protection relays or transmission line relays on transmission lines terminated only with a transformer to ……" since it appears from the NERC Webinar on 11/23/10 that the intention was address the possible locations where phase protection for the transformer could exist and not infer that this protection was needed at both locations.
Response: Thank you for your comments. 1. The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point.				

2. The drafting team has considered this comment and similar comments and has modified the text of the standard as appropriate.				
Joseph O'Brien	Northern Indiana Public Service Co.	6	Negative	See submitted comment form under "Posted for Comment"
Response: Thank you for your comments. Please refer to the drafting team responses in the Consideration of Comments document.				
Michelle DAntuono	Occidental Chemical	5	Negative	1. Further clarification is needed for criterion 10 in R1. Is it the intention of this criterion that all applicable transformers must have load responsive protection to prevent mechanical damage from a through fault? If load responsive protection for the transformer element does not presently exist, i.e. only differential protection exists for the transformer element, will load responsive transformer protection have to be added to comply with this criterion? 2. It is also suggested that R1 Criterion 10 wording be changed to "Set transformer fault protection relays or transmission line relays on transmission lines terminated only with a transformer to …….." since it appears from the NERC Webinar on 11/23/10 that the intention was address the possible locations where phase protection for the transformer could exist and not infer that this protection was needed at both locations.
Response: Thank you for your comments. 1. The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point. 2. The drafting team has considered this comment and similar comments and has modified the text of the standard as appropriate.				
Douglas Hohlbaugh	Ohio Edison Company	4	Negative	Please see FirstEnergy's comments submitted separately through the comment period posting
Response: Thank you for your comments. Please refer to the drafting team responses in the Consideration of Comments document.				
Chifong L. Thomas	Pacific Gas and Electric Company	1	Negative	1. R2 is not clear. Is the requirement that OSB elements should not prevent the relay from tripping for a fault during overloaded conditions? 2. R6 does not include circuits or facilities that may have been deemed critical facilities for CIP purposes. 3. R7 timeframe to comply is 24 months. We are not sure that this is sufficient time to

				get a job approved and constructed to replace relays on a terminal if they cannot be set to comply. Few relays 200kV and above did not meet loadability requirements, but we suspect there are many more at 100-200kv and below 100kV. 4. There is no stated requirement for periodic review, except for the Planning Coordinator. Does this imply an annual review and documentation for all facilities that are in scope of this standard?
Response: Thank you for your comments. 1. This is exactly what the requirement is. The drafting team notes that Requirement R2 does not add a new obligation on Transmission Owners, Generator Owners, and Distribution Providers; it only explicitly states in PRC-023-2 an obligation that presently is included in Attachment A, section 2 of PRC-023-1. 2. Again, correct. The methodology and criteria are different between CIP and this standard. The criteria in Attachment B were selected to identify circuits that present a risk of cascading outages if relay loadability requirements are not met, consistent with the reliability objective of this standard. 3. The drafting team has considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1. 4. As with all standards, entities are expected to be in compliance all the time. Specification of a periodic review for the Transmission Owner, Generator Owner, and Distribution Provider seems unnecessary; they must naturally perform whatever reviews are necessary to assure continued compliance.				
Richard J. Padilla	Pacific Gas and Electric Company	5	Negative	1. R2 is not clear to me. Is the requirement that OSB elements should not prevent the relay from tripping for a fault during overloaded conditions? 2. R6 does not include circuits or facilities that may have been deemed critical facilities for CIP purposes. 3. R7 timeframe to comply is 24 months. I am not sure that this is sufficient time to get a job approved and constructed to replace relays on a terminal if they cannot be set to comply. Few relays 200kV and above did not meet loadability requirements, but I suspect there are many more at 100-200kv and below 100kV. 4. There is no stated requirement for periodic review, except for the Planning Coordinator. Does this imply an annual review and documentation for all facilities that are in scope of this standard?
Response: Thank you for your comments. 1. This is exactly what the requirement is. The drafting team notes that Requirement R2 does not add a new obligation on Transmission Owners, Generator Owners, and Distribution Providers; it only explicitly states in PRC-023-2 an obligation that presently is included in Attachment A, section 2 of PRC-023-1. 2. Again, correct. The methodology and criteria are different between CIP and this standard. The criteria in Attachment B were selected to identify circuits that present a risk of cascading outages if relay loadability requirements are not met, consistent with the reliability objective of this standard. 3. The drafting team has considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1. 4. As with all standards, entities are expected to be in compliance all the time. Specification of a periodic review for the Transmission Owner, Generator				

Owner, and Distribution Provider seems unnecessary; they must naturally perform whatever reviews are necessary to assure continued compliance.				
Colt Norrish	PacifiCorp	1	Negative	1. PacifiCorp agrees with what it understands are the general concepts contained in Applicability Section 4.2, Requirements R6 and R7, and Attachment B of the proposed PRC-023-2. Namely, that: 1) the standard applies to all facilities (defined in Attachment A) above 200 kV and some facilities below 200 kV; 2) the Planning Coordinator is responsible for identifying the 100 â€“ 200 KV facilities (defined in Attachment A) to which the standard will apply (based on Attachment B); 3) some combination of the Regional Entity and the Planning Coordinator are responsible for identifying below 100 kV facilities (defined in Attachment A) to which the standard will apply (based on Attachment B); and 4) Transmission Owners, Generator Owners, and Distribution Providers that own the facilities that have been deemed applicable are responsible for complying with the requirements of the standard. If PacifiCorp's understanding of these concepts is generally correct, they must be more clearly stated in PRC-023-2. 2. As is currently drafted, the language contained in the applicability section, Requirements R6 and R7, and Attachment B are circular, unclear, and redundant. In order for registered entities to understand their obligations, the standards must be absolutely clear on what is required and by whom. PacifiCorp suggests the following: 1) remove R6 because it is redundant with the Applicability Section 4.2 (or vice versa) and clarify the role of the Planning Coordinator and the application of Attachment B criteria; 2) Applicability Section 4.2.3 and the second bullet in Attachment B appear to contradict as Section 4.2.3 defines a role for the Planning Coordinator whereas the second bullet in Attachment B does not -this may be correct for some reason, however, the role of the Planning Coordinator and the Regional Entity in evaluating facilities below 100 kV must be more clearly defined. PacifiCorp does not have any substantive issues with the Attachment B criteria. However, in order to be enforceable, the legal obligations imposed on registered entities under PRC-023-2 must be more clearly stated.
John Apperson	PacifiCorp	3		
Sandra L. Shaffer	PacifiCorp	5		
Scott L Smith	PacifiCorp	6		
Response: Thank you for your comments. 1. Extensive revisions were made to Attachment B and throughout the standard to improve clarity. The drafting team believes that these responsibilities are now clearly defined. 2. The drafting team has removed parts 6.1 and 6.2 from Requirement R6 to avoid redundancy, and has revised the Applicability section and Attachment B based on industry comments to provide clarity. The drafting also has deleted Requirement R7 and modified the Effective Dates section to address the timeframe in which Facility owners must comply with Requirements R1 through R5 when the Planning Coordinator identifies a circuit for which the Facility owner must comply with the standard.				
Anthony E Jablonski	ReliabilityFirst Corporation	10	Affirmative	ReliabilityFirst votes affirmative but offers the following comments. 1.Within the Applicability there are references to PRC-023 –but the version number is missing.

				2.R1 should be broken down into two separate requirements. The first requiring the applicable entities to use one of the criteria. The second requiring the applicable entity to evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. This will make the VSL designations cleaner.
Response: Thank you for your comments. 1) The drafting team has revised the standard as you suggest. 2) The drafting team believes that this comment addresses approved content in PRC-023-1, and is therefore outside the scope of this project.				
John C. Allen	Rochester Gas and Electric Corp.	1	Negative	Criteria 10 under Requirement 1 could subject the industry to adding phase overcurrent protection to a large number of transformers. Clarification is needed as to the implications of this requirement.
Response: Thank you for your comments. The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point				
Rich Salgo	Sierra Pacific Power Co.	1	Negative	We cast a negative ballot because the Standard as written, contemplates a fairly complicated planning study process (Attachment B), to determine which facilities can be included/excluded from compliance with the relay loadability standard itself. This was done for good intent, and was a compromise between the industry's position of 200kV and above applicability, and FERC's general position to apply this Standard to everything above 100kV. However, now we have a recent FERC Order on the definition of BES (Order 743). This Order compels NERC to develop a new BES definition that is 100kV-based, yet allows for exclusion criteria that NERC is to develop. As such, this should supersede the criteria proposed in Attachment B. Continuing with Appendix B as written will cause the unintended consequence of having conflicts between the ultimate BES list and the list of PRC-023-applicable facilities. It seems they should be the same.
Response: Thank you for your comments. All circuits that are necessary for operating the interconnected transmission network are not necessarily important for the purposes of PRC-023. The criteria in Attachment B were selected to identify circuits that present a risk of cascading outages if relay loadability requirements are not met, consistent with the reliability objective of this standard. Thus, it is expected that the list of circuits identified by applying the criteria in Attachment B will be a subset of the Bulk Electric System. This standard like all others will need to be reviewed when the new definition of the Bulk Electric System is approved.				

Long T Duong	Snohomish County PUD No. 1	1	Affirmative	The District believes to be an unintended consequence – a Catch-22 – from the interaction of the revised CIP-002-4 Attachment 1's Criteria 1.4 (Blackstart Resources) and 1.5 (identified Cranking Paths) with the control center size and facility exceptions in 1.15, 1.16 and 1.17. This interaction will cause many if not all registered TOPs, BAs and Generation Owners that control Blackstart Resources used in a TOP restoration plan to become subject to CIP-002 through CIP-009, regardless of entity size. EOP-005 requires all TOPs to have a restoration plan. The District's reading of EOP-005 indicates that each TOP must identify one or more Blackstart Resources. CIP-002-4 Criterion 1.4 requires a TOP to identify each such Blackstart Resource identified in its restoration plan as a critical asset. Criterion 1.5 requires the identification of certain Cranking Paths as critical assets. Criterion 1.15 requires that each generation control center or backup control center used to control a Blackstart Resource identified under Criterion 1.4 be identified as a critical asset, without any exception for generation control center size (1500 MW). Criterion 1.16 requires each transmission control center or backup control center used to control a Cranking Path identified under Criterion 1.5 be identified as a critical asset, without any exception for TOP control center size. Criterion 1.17 requires each Balancing Authority control center or backup control center used to control a Blackstart Resource identified under Criterion 1.4 be identified as a critical asset, without any exception for Balancing Authority control center size (1500 MW). In effect, Criterion 1.4 swallows all exceptions created under 1.15 through 1.17, with the possible exception of a generation-only BA that does not have any Blackstart Resource obligations to its TOP. All vertically integrated utilities would be responsible for CIP-002 through CIP-009, including small BAs and TOPs that do not own any other Critical Assets. To address this problem, we propose the following edits to 1.4 and 1.5 shown in redline CAPS/strikeout: 1.4. Each Blackstart Resource identified in the RESTORATION PLAN FOR A Transmission Operator's restoration plan SERVING LOAD OR GENERATION EQUAL TO OR GREATER THAN AN AGGREGATE OF 1500 MW IN A SINGLE INTERCONNECTION. 1.5. The Facilities comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource(S) IDENTIFIED IN 1.4. to the first interconnection point of the generation unit(s) to be started, or up to the point on the Cranking Path where two or more path options exist, as identified in the Transmission Operator's restoration plan. This surgical approach ensures that generation, TOP and BA control centers with responsibility for other critical generation and transmission assets are still responsible for full CIP-002-4 through CIP-009 compliance. However, small BA/TOP systems with no initial obligations to the RC

				and larger TOPs for regional restoration would not be deemed "critical." The experience of these smaller systems is that their restoration obligations have not been relied upon to restore the BES, but rather to start generation to serve local load after a system separation – and then to wait for direction from the RC on resynchronization with the rest of the BES, once voltage and frequency are stabilized. While we recognize that cyber events may have an impact on the availability of resources, the fundamental fact is the vast majority of Blackstart Resources and control centers will be protected under CIP-002 through -009, because they will be classified as Critical/High Impact under the proposed criteria, as revised above. Thus the revised criteria support rather than undermine the distinction between categorization of big iron/big aluminum resources and their associated control centers as Critical or High Impact in the development of CIP-002-4. The categorization and development of security controls for smaller resources as either medium or low impact for the BES, should be addressed through development of additional bright line criteria and associated security controls in the next phase of this project (CIP-002-5 or CIP-010/011.)
Response: Thank you for your comments. The drafting team notes that the criteria in Attachment B are intentionally different than the CIP requirements for identifying critical facilities. It appears that the comments submitted would be more appropriately submitted to the Project 2008-06 — Cyber Security — Order 706 drafting team.				
Charles H Yeung	Southwest Power Pool	2	Negative	SPP supports the comments submitted by the ISO RTO Council Standards Review Committee which raise many concerns on the requirements proposed.
Response: Thank you for your comments. Please see our response to the comments submitted by the ISO RTO Council Standards Review Committee.				
Travis Metcalfe	Tacoma Public Utilities	3	Negative	1. Transmission or Transformers that normally would not be considered BES assets are subject to inclusion by the Planning Coordinator. The criteria for inclusion have not been developed yet. 2. Attachment A Section 1.6 was added due to FERC Order 733, but it is still vague what includes "Supervisory Elements". Please clarify supervisory elements (Does it include RTUs?) 3. Detailed direction about relay setting methodology could be expanded to 110-kV level by this revision. Much more research should be devoted to such detailed changes to evaluate impact to other protection and operation constraints, before such settings are mandatory.

				4. The new requirement (R2) may present conflicting choices for a relay engineer, since out-of-step blocking is technically challenging to set, sense and discriminate from certain loading and fault conditions.

Response: Thank you for your comments.

1. The NERC Statement of Compliance Registry Criteria permits application of NERC Reliability Standards to certain facilities operated below 100 kV, such as for transmission elements operated below 100 kV that are included on a critical facilities list defined by the Regional Entity. The test by which the Regional Entity may make this determination is outside the scope of this standard. The criteria by which the Planning Coordinators determine for which of the circuits on the list the applicable entities must comply with the standard are defined in Attachment B.
2. Attachment A, Section 1.6 has been modified to include supervisory elements only as they apply to current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications. The drafting team believes this modification provides clarity that this section does not apply to RTUs and other applications.
3. The drafting team understands your concern and will place this item in the issues database for future consideration in the next general revision of the standard. However, the drafting team notes that PRC-023-1 already applies to lines operated at 100 kV to 200 kV and the drafting team does not believe that a significant number of sub-100 kV circuits will be impacted. As such, the drafting team disagrees that more research is required prior to implementing PRC-023-2.
4. The drafting team notes that Requirement R2 does not add a new obligation on Transmission Owners, Generator Owners, and Distribution Providers; it only explicitly states in PRC-023-2 an obligation that presently is included in Attachment A, Section 2 of PRC-023-1.

Keith Morisette	Tacoma Public Utilities	4	Negative	Tacoma Power is submitting a Negative vote due to the following concerns: · 1. Transmission or Transformers that normally would not be considered BES assets are subject to inclusion by the Planning Coordinator. The criteria for inclusion have not been developed yet. 2. Attachment A Section 1.6 was added due to FERC Order 733, but it is still vague what includes “Supervisory Elements”. Please clarify supervisory elements (Does it include RTUs?) 3. Detailed direction about relay setting methodology could be expanded to 110-kV level by this revision. Much more research should be devoted to such detailed changes to evaluate impact to other protection and operation constraints, before such settings are mandatory.

				4. The new requirement (R2) may present conflicting choices for a relay engineer, since out-of-step blocking is technically challenging to set, sense and discriminate from certain loading and fault conditions. Thank you for consideration of these concerns.
Response: Thank you for your comments. 1. The NERC Statement of Compliance Registry Criteria permits application of NERC Reliability Standards to certain facilities operated below 100 kV, such as for transmission elements operated below 100 kV that are included on a critical facilities list defined by the Regional Entity. The test by which the Regional Entity may make this determination is outside the scope of this standard. The criteria by which the Planning Coordinators determine for which of the circuits on the list the applicable entities must comply with the standard are defined in Attachment B. 2. Attachment A, Section 1.6 has been modified to include supervisory elements only as they apply to current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications. The drafting team believes this modification provides clarity that this section does not apply to RTUs and other applications. 3. The drafting team understands your concern and will place this item in the issues database for future consideration in the next general revision of the standard. However, the drafting team notes that PRC-023-1 already applies to lines operated at 100 kV to 200 kV and the drafting team does not believe that a significant number of sub-100 kV circuits will be impacted. As such, the drafting team disagrees that more research is required prior to implementing PRC-023-2. 4. The drafting team notes that Requirement R2 does not add a new obligation on Transmission Owners, Generator Owners, and Distribution Providers; it only explicitly states in PRC-023-2 an obligation that presently is included in Attachment A, Section 2 of PRC-023-1.				
Michael C Hill	Tacoma Public Utilities	6	Negative	1. Transmission or Transformers that normally would not be considered BES assets are subject to inclusion by the Planning Coordinator. The criteria for inclusion have not been developed yet. 2. Attachment A Section 1.6 was added due to FERC Order 733, but it is still vague what includes “Supervisory Elements”. Please clarify supervisory elements (Does it include RTUs?) 3. Detailed direction about relay setting methodology could be expanded to 110-kV level by this revision. Much more research should be devoted to such detailed changes to evaluate impact to other protection and operation constraints, before such settings are mandatory.

				4. The new requirement (R2) may present conflicting choices for a relay engineer, since out-of-step blocking is technically challenging to set, sense and discriminate from certain loading and fault conditions.

Response: Thank you for your comments.

1. The NERC Statement of Compliance Registry Criteria permits application of NERC Reliability Standards to certain facilities operated below 100 kV, such as for transmission elements operated below 100 kV that are included on a critical facilities list defined by the Regional Entity. The test by which the Regional Entity may make this determination is outside the scope of this standard. The criteria by which the Planning Coordinators determine for which of the circuits on the list the applicable entities must comply with the standard are defined in Attachment B.
2. Attachment A, Section 1.6 has been modified to include supervisory elements only as they apply to current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications. The drafting team believes this modification provides clarity that this section does not apply to RTUs and other applications.
3. The drafting team understands your concern and will place this item in the issues database for future consideration in the next general revision of the standard. However, the drafting team notes that PRC-023-1 already applies to lines operated at 100 kV to 200 kV and the drafting team does not believe that a significant number of sub-100 kV circuits will be impacted. As such, the drafting team disagrees that more research is required prior to implementing PRC-023-2.
4. The drafting team notes that Requirement R2 does not add a new obligation on Transmission Owners, Generator Owners, and Distribution Providers; it only explicitly states in PRC-023-2 an obligation that presently is included in Attachment A, Section 2 of PRC-023-1.

Larry D. Grimm	Texas Reliability Entity	10	Negative	1. In R1, criterion 9 is missing some words at the end. We think it is supposed to say ". . . from the load to the system under any system configuration." 2. In R1, criterion 12(c), it appears that the reference should be changed from "criterion 12" to "criterion 12(b)". 3. In Attachment B, criterion B1, "Texas Interconnection" should be changed to "ERCOT Interconnection." That is the correct name of this Interconnection. (FYI, the ERCOT Interconnection does not include several parts of the Texas BES, which are in WECC, SPP, and SERC.) 4. In R1, criteria 1, 4, and 10, the draft specifies that Facility Ratings are to be "expressed in amperes." In our experience these ratings are ordinarily expressed in MVA. In criteria 11, a rating is referenced, but the units are not specified. We suggest

				either (a) not specifying units for these ratings in the standard, or (b) specifying “MVA” rather than “amperes.” 5. In R1, criteria 10 and 11, the references to “operator established emergency transformer rating” should be changed to “owner established emergency transformer rating.” Note that FAC-008 and FAC-009 call on the Transmission Owner and Generator Owner entities to establish Facility Ratings. 6. In R5, why is the Regional Entity designated to receive a list of facilities with relays set according to criterion 12? Texas RE does not ordinarily act as a clearinghouse for this kind of information. If the intention is to share this information with other entities, this list should be provided to the Reliability Coordinator or some other appropriate functional entity, rather than to the Regional Entity. 7. In Attachment B, criterion B3, “plant owner” should be changed to “Generator Owner” and “Transmission Entity” should be changed to “Transmission Owner,” in order to clearly designate the responsible entities. 8. In Attachment B, criterion B4, the reference to “power flow analysis” should be changed to “power flow assessment,” in order to make it consistent with the term used in R6. 9. In Attachment B, criterion B4, the second bullet is unclear as written. We suggest changing it to read as follows: “For circuits operated between 100 kV and 200 kV, evaluate the post-contingency loading against the Facility Rating after contingency evaluations per TPL-003, Category A, B, and C3 with the near-term load flow case.”

Response: Thank you for your comments

1. The text has been corrected.
2. The drafting team believes that this comment addresses approved content in PRC-023-1, and is therefore outside the scope of this project. The drafting team will place this item in the issues database for future consideration in the next general revision of the standard.
3. In response to other comments, Attachment B, criterion B1 has been revised to delete the reference to the Texas Interconnection.
4. The drafting team believes that this comment addresses existing content in PRC-023-1, and is therefore outside the scope of this project.
5. The drafting team believes that this comment addresses existing content in PRC-023-1, and is therefore outside the scope of this project.
6. The Regional Entity (RE), via the delegation agreements, is a part of the ERO; thus, by submitting the information to the RE, the ERO will have the information available to respond to requests from users, owners, and operators of the BES.
7. This criterion references Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001, and therefore refers to entities consistent with the

description in NUC-001 which does not refer to NERC Functional Model entities. 8. The drafting team notes that the power flow analysis required in criterion B4 is one aspect of the assessment identified in Requirement R6. Criterion B4 therefore is not inconsistent with Requirement R6. 9. A number of changes have been made to criterion B4 in response to industry comments. While the drafting team has not incorporated this suggestion, we believe the modifications to the criterion provide clarity desired by the commenter.				
Keith V. Carman	Tri-State G & T Association, Inc.	1	Negative	Reference Tri-State Generation & Transmission Assn., Inc. comments submitted to NERC via the Project 2010-13 Formal Comment link.
Janelle Marriott	Tri-State G & T Association, Inc.	3	Negative	Reference Tri-State Generation and Transmission Assn., Inc. Formal comments submitted to NERC electronically via the Project 2010-13 Formal Comment link. Thank you.
Response: Thank you for your comments. Please refer to the drafting team responses in the Consideration of Comments document.				
Jonathan Appelbaum	United Illuminating Co.	1	Negative	The drafting team should include a criteria for Phase Angle Regulators and Series reactors. These are types of transformers and for clarity purposes should be called out specifically.
Response: Thank you for your comments. The drafting team believes that the phase angle regulating transformers are already included in the standard in Criteria 10 and 11, and that series reactors are already included as part of the element in which they are inserted. This comment will be considered as we prepare future versions of the standard.				
Allen Klassen	Westar Energy	1	Affirmative	Please define the term "mechanical withstand" used in B.R1.10.
Response: Thank you for your comments. The mechanical withstand is defined is IEEE C57.109-1993, *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration* and a reference to this standard has been added as a footnote to address your concerns.				
Brandy A Dunn	Western Area Power Administration	1	Negative	1. The different wording regarding applicability to transmission lines between 100-kV and 200-kV is confusing as it is not clear from these statements whether or not the Planning Coordinator makes this determination. Under “Applicability”, 4.2.2 states: Transmission lines operated at 100 kV to 200 kV that the Planning Coordinator has determined are required to comply with this standard. Attachment B indicates applicable circuits are: Transmission lines operated at 100 kV to 200 kV [….]. 2. Similarly the different wording regarding applicability to transformers having low voltage terminals between 100-kV and 200-kV is confusing as it is not clear from these statements whether or not the Planning Coordinator makes this determination. Under “Applicability”, 4.2.5 states: Transformers with low voltage terminals connected at 100 kV to 200 kV that the Planning Coordinator has determined are required to comply with this standard. Attachment B indicates applicable circuits are: [….] transformers with low voltage terminals connected at 100 kV to 200 kV

				3. Regarding the former comments 1 and 2, Attachment B could reference 4.2.1 - 4.2.6, or repeat them exactly, unless there is another intent of describing applicability again under Attachment B. 4. In "B. Requirements R1.": suggest the following mod from: "power factor angle of 30 degrees." to: "power factor angle of 30 degrees, where the power factor angle is material to the operation of the relay such as with mho type characteristics." 5. 6.1 and 6.2 are further re-statements of applicability criteria. It would be less confusing to have these appear one place in the document and reference them elsewhere, or repeat them identically each time they are used. 6. Attachment A - The meaning of 1.6 and its relationship to the second bullet under 2.1 is unclear and confusing.
Response: Thank you for your comments. 1. The drafting team has divided the Applicability section to differentiate between circuits subject to Requirement R6 (the circuits to which the Planning Coordinator must apply Attachment B) and the circuits subject to Requirements R1 through R5 (the circuits identified by the Planning Coordinator through the Application of Attachment B). The drafting team believes this change addresses the commenter's concern. 2. The drafting believes the changes to the Applicability section address this concern also. 3. The drafting team has modified Attachment B to use the same description as the circuits subject to Requirement R6 in the Applicability section. 4. The drafting team believes that this comment addresses existing content in PRC-023-1, and is therefore outside the scope of this project. 5. 1) The drafting team has eliminated parts 6.1 and 6.2 from Requirement R6. The drafting team understands that repeating this information in Requirement R6 and in Attachment B is redundant and potentially confusing. In addition, the drafting team has revised the text in Attachment B to more clearly convey the intent. 6. The drafting team has modified believes that this relationship is clear. Section 1.6 specifically includes supervisory elements associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications, and 2.1 (second bullet) excludes all elements only enabled during a loss of communication, with the exception of supervisory elements included in Section 1.6				
Forrest Brock	Western Farmers Electric Coop.	1	Affirmative	WFEC recognizes the work of the SDT in composing a draft standard for relay loadability that displays the team's effort to keep the requirements within the standard focused on achieving reliability for the BES.
Response: Thank you for your comment.				
Gregory L Pieper	Xcel Energy, Inc.	1	Negative	Sections 4.2.3 and 4.2.6, in the applicability section, are of concern to us because they include facilities that would not otherwise be part of the Bulk Electric System (i.e. facilities operating less than 100 kV). Other drafting teams have contemplated including generating units connected at
Michael Ibold	Xcel Energy, Inc.	3		

Liam Noailles	Xcel Energy, Inc.	5		less than 100 kV, and have been advised that if they did that, Generator Owners that were not Registered Entities with NERC would have to register and would be required to comply with ALL Generator Owner requirements in ALL of the NERC standards. This same risk exists under the currently proposed PRC-023-2. We suggest that a requirement be added to require the PA to notify the unregistered entity, if their facility has been determined to be critical. In addition, there should be additional time permitted for those entities to get into compliance and that should be reflected in the implementation plan.
David F. Lemmons	Xcel Energy, Inc.	6		

Response: Thank you for your comments.

The drafting team understands the concern with including facilities operated below 100 kV; however, the NERC Statement of Compliance Registry Criteria does allow Regional Entities the ability to identify such facilities operated below 100 kV as required to comply with NERC Reliability Standards. The drafting team has replaced the phrase “critical for the purposes of the Compliance Registry” with text from the ¶60 of Order No. 733, which references text in section III.d.2 of the NERC Statement of Compliance Registry Criteria, so the second category of circuits to be evaluated now refers to transmission lines and transformers operated below 100 kV “that are included on a critical facilities list defined by the Regional Entity.” The drafting team made corresponding modifications to the Applicability section.

PRC-023-2 Mapping of Requirements from PRC-023-1 and Directed Modifications in Order No. 733

Mapping of PRC-023-1 to PRC-023-2			
Requirement in the Existing PRC-023-1	**Location in PRC-023-2 (1st Posting)**	**Location in PRC-023-2 (2nd Posting)**	**Needed for Reliability**
R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (R1.1 through R1.13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. 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:	Requirement R1	Requirement R1	Yes
R1.1. Set transmission line relays so they do not operate at or below 150% of the highest seasonal Facility Rating of a circuit, for the available defined loading duration nearest 4 hours (expressed in amperes). **R1.2.** Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating2 of a circuit (expressed in amperes). **R1.3.** Set transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability (using a 90-degree angle between the sending end and receiving-end voltages and either reactance or complex impedance) of the circuit (expressed in amperes) using one of the following to perform the power transfer calculation: **R1.3.1.** An infinite source (zero source impedance) with a 1.00 per unit bus voltage at each end of the line. **R1.3.2.** An impedance at each end of the line, which reflects the actual system source impedance with a 1.05 per unit voltage behind each source impedance. **R1.4.** Set transmission line relays on series compensated transmission lines so they do not operate at or below the maximum power transfer capability of the line, determined as the greater of: - 115% of the highest emergency rating of the series capacitor. - 115% of the maximum power transfer capability of the circuit (expressed in amperes), calculated in accordance	Requirements R1.1 through R1.13 are now criteria 1 through 13 under Requirement R1	Requirements R1.1 through R1.13 are now criteria 1 through 13 under Requirement R1	Yes

Mapping of PRC-023-1 to PRC-023-2			
Requirement in the Existing PRC-023-1	**Location in PRC-023-2 (1st Posting)**	**Location in PRC-023-2 (2nd Posting)**	**Needed for Reliability**
with R1.3, using the full line inductive reactance. **R1.5.** Set transmission line relays on weak source systems so they do not operate at or below 170% of the maximum end-of-line three-phase fault magnitude (expressed in amperes). **R1.6.** Set transmission line relays applied on transmission lines connected to generation stations remote to load so they do not operate at or below 230% of the aggregated generation nameplate capability. **R1.7.** Set transmission line relays applied at the load center terminal, remote from generation stations, so they do not operate at or below 115% of the maximum current flow from the load to the generation source under any system configuration. **R1.8.** Set transmission line relays applied on the bulk system-end of transmission lines that serve load remote to the system so they do not operate at or below 115% of the maximum current flow from the system to the load under any system configuration. **R1.9.** Set transmission line relays applied on the load-end of transmission lines that serve load remote to the bulk system so they do not operate at or below 115% of the maximum current flow from the load to the system under any system configuration. **R1.10.** Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer so that they do not operate at or below the greater of: - 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment. - 115% of the highest operator established emergency transformer rating. **R1.11.** For transformer overload protection relays that do not comply with R1.10 set the relays according to one of the following: - Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater. The protection must allow this overload for at least 15 minutes to allow for the operator			

Mapping of PRC-023-1 to PRC-023-2			
Requirement in the Existing PRC-023-1	**Location in PRC-023-2 (1st Posting)**	**Location in PRC-023-2 (2nd Posting)**	**Needed for Reliability**
to take controlled action to relieve the overload. - Install supervision for the relays using either a top oil or simulated winding hot spot temperature element. The setting should be no less than 100° C for the top oil or 140° C for the winding hot spot temperature3. **R1.12.** When the desired transmission line capability is limited by the requirement to adequately protect the transmission line, set the transmission line distance relays to a maximum of 125% of the apparent impedance (at the impedance angle of the transmission line) subject to the following constraints: **R1.12.1.** Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer. **R1.12.2.** Evaluate the relay loadability in amperes at the relay trip point at 0.85 per unit voltage and a power factor angle of 30 degrees. **R1.12.3.** Include a relay setting component of 87% of the current calculated in R1.12.2 in the Facility Rating determination for the circuit. **R1.13.** Where other situations present practical limitations on circuit capability, set the phase protection relays so they do not operate at or below 115% of such limitations.			
R2. The Transmission Owner, Generator Owner, or Distribution Provider that uses a circuit capability with the practical limitations described in R1.6, R1.7, R1.8, R1.9, R1.12, or R1.13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.	Requirement R3	Requirement R3	Yes
R3. The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV that must meet Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability.	Requirement R6	Requirement R6	Yes

Mapping of PRC-023-1 to PRC-023-2			
Requirement in the Existing PRC-023-1	Location in PRC-023-2 (1st Posting)	Location in PRC-023-2 (2nd Posting)	Needed for Reliability
R3.1. The Planning Coordinator shall have a process to determine the facilities that are critical to the reliability of the Bulk Electric System. **R3.1.1.** This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.	Determination of facilities that must comply with this standard is now contained in Attachment B	Determination of facilities that must comply with this standard is now contained in Attachment B	Yes
R3.2. The Planning Coordinator shall maintain a current list of facilities determined according to the process described in R3.1.	Requirement R6, Part 6.3	Requirement R6, Part 6.1	Yes
R3.3. The Planning Coordinator shall provide a list of facilities to its Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within 30 days of the establishment of the initial list and within 30 days of any changes to the list.	Requirement R6, Part 6.5	Requirement R6, Part 6.2	Yes

Mapping of Directed Changes in Order No. 733				
Paragraph in Order No. 733	Text	Location in PRC-023-2 (1st Draft)	Location in PRC-023-2 (2nd Draft)	Needed for Reliability
60	With respect to sub-100 kV facilities, we adopt the NOPR proposal and direct the ERO to modify PRC-023-1 to apply an “add in” approach to sub-100 kV facilities that are owned or operated by currently-Registered Entities or entities that become Registered Entities in the future, and are associated with a facility that is included on a critical facilities list defined by the Regional Entity. We also direct that additions to the Regional Entities’ critical facility list be tested for their applicability to PRC-023-1 and made subject to the Reliability Standard as appropriate.	Requirement R6 and Attachment B	Requirement R6 and Attachment B	Yes
69	Finally, pursuant to section 215(d)(5) of the FPA, we	Requirement	Requirement	Yes

Mapping of Directed Changes in Order No. 733				
Paragraph in Order No. 733	**Text**	**Location in PRC-023-2 (1st Draft)**	**Location in PRC-023-2 (2nd Draft)**	**Needed for Reliability**
	direct the ERO to modify Requirement R3 of the Reliability Standard to specify the test that planning coordinators must use to determine whether a sub-200 kV facility is critical to the reliability of the Bulk-Power System. We direct the ERO to file its test, and the results of applying the test to a representative sample of utilities from each of the three Interconnections, for Commission approval no later than one year from the date of this Final Rule.	R6 and Attachment B	R6 and Attachment B	
97	Finally, commenters argue that there should be some mechanism for entities to challenge criticality determinations. We agree that such a mechanism is appropriate and direct the ERO to develop an appeals process (or point to a process in its existing procedures) and submit it to the Commission no later than one year after the date of this Final Rule.	To be addressed outside PRC-023-2	To be addressed outside PRC-023-2	Yes
162	We agree with the PSEG Companies and direct the ERO to consider "islanding" strategies that achieve the fundamental performance for all islands in developing the new Reliability Standard addressing stable power swings.	Considered in Phase I; will be addressed in Phase III	Considered in Phase I; will be addressed in Phase III	Yes
186	However, we will adopt the NOPR proposal to direct the ERO to modify PRC-023-1 to require that transmission owners, generator owners, and distribution providers give their transmission operators a list of transmission facilities that implement sub-requirement R1.2.	Requirement R4	Requirement R4	Yes
203	We adopt the NOPR proposal and direct the ERO to modify sub-requirement R1.10 so that it requires entities to verify that the limiting piece of equipment is capable of sustaining the anticipated overload for the longest clearing time associated with the fault.	Requirement R1, criterion 10	Requirement R1, criterion 10	Yes
224	While we are not adopting the NOPR proposal, we direct the ERO to document, subject to audit by the Commission, and to make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant sub-requirement R1.12.	Requirement R5 collects data; ERO to provide list outside PRC-023-2	Requirement R5 collects data; ERO to provide list outside PRC-023-2	Yes

Mapping of Directed Changes in Order No. 733				
Paragraph in Order No. 733	**Text**	**Location in PRC-023-2 (1st Draft)**	**Location in PRC-023-2 (2nd Draft)**	**Needed for Reliability**
237	We adopt the NOPR proposal and direct the ERO to modify the Reliability Standard to add the Regional Entity to the list of entities that receive the critical facilities list. [sub-requirement R3.3]	Requirement R6, Part 6.5	Requirement R6, Part 6.2	Yes
244	We adopt the NOPR proposal and direct the ERO to include section 2 of Attachment A in the modified Reliability Standard as an additional Requirement with the appropriate violation risk factor and violation severity level.	Requirement R2	Requirement R2	Yes
264	After further consideration, and in light of the comments, we will not direct the ERO to remove any exclusion from section 3, except for the exclusion of supervising relay elements in section 3.1. Consequently, we direct the ERO to revise section 1 of Attachment A to include supervising relay elements on the list of relays and protection systems that are specifically subject to the Reliability Standard.	Attachment A, Section 1.6	Attachment A, Section 1.6	Yes
283	Additionally, in light of our directive to the ERO to expand the Reliability Standard's scope to include sub-100 kV facilities that Regional Entities have already identified as necessary to the reliability of the Bulk-Power System through inclusion in the Compliance Registry, we direct the ERO to modify the Reliability Standard to include an implementation plan for sub-100 kV facilities.	Implementat ion Plan	Implementat ion Plan	Yes
284	We also direct the ERO to remove the exceptions footnote from the "Effective Dates" section.	Footnote 1 removed from the "Effective Dates: section	Footnote 1 removed from the "Effective Dates: section	Yes

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NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Analysis of Violation Risk Factors and Violation Severity Levels
PRC-023-2 — Transmission Relay Loadability

This document provides the justification for assignment of Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs), identifying how each proposed VRF and VSL meets NERC's criteria and FERC's Guidelines. NERC's criteria for setting VRFs and VSLs; FERC's five guidelines (G1 – G5) for approving VRFs; and FERC's four guidelines (G1-G4) for setting VSLs are provided at the end of this document.

VRF and VSL Justifications for R1		
R1	Proposed VRF	High
	NERC VRF Discussion	*The proposed requirement, R1, states that each Transmission Owner, Generator Owner, and Distribution Provider shall apply one of several criteria to ensure that its load-responsive relaying does not trip due to load responsive conditions. The VRF for Requirement R1 is a "High" because, should the load-responsive relaying trip improperly due to load conditions, it 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 G1 Discussion	Guideline 1- Consistency w/ Blackout Report *This requirement is directly related to 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.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *Requirement R2 has a similar reliability objective and is assigned a High VRF*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *Not applicable. There are no other NERC Reliability Standards that address similar reliability goals.*
	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 R1 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 and therefore this guideline does not apply.*
	Proposed Lower VSL	*N/A*
	Proposed Moderate VSL	*N/A*
	Proposed High VSL	*N/A*

VRF and VSL Justifications for R1		
	Proposed Severe VSL	*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.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The proposed VSL for Requirement is consistent with the approved VSL for the similar Requirement R1 within PRC-023-1.*
	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 R2 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, R1.*
	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 and VSL Justifications for R2		
R2	Proposed VRF	High
	NERC VRF Discussion	*The proposed requirement, R2, states that each Transmission Owner, Generator Owner, and Distribution Provider shall ensure that its out-of-step blocking elements allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. The VRF for Requirement R2 is a "High" because a protection system if inhibited from operating by the out of step blocking could prevent it from operating for fault conditions. 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.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *Not applicable. Out-of-step blocking elements did not prevent tripping of phase protective relays during the August 14, 2003 Northeast Blackout.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *Requirement R2 references Requirement R1 and both requirements are assigned a "High" VRF.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *Not applicable. There are no other NERC Reliability Standards that address similar reliability goals.*
	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 out-of-step blocking elements allow tripping of phase protective relays for faults that occur during the loading conditions used to verify transmission line relay loadability per Requirement R1. This requirement is in the planning time frame and 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.*
	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 and therefore this guideline does not apply.*
	Proposed Lower VSL	*N/A*
	Proposed Moderate VSL	*N/A*
	Proposed High VSL	*N/A*
	Proposed Severe VSL	*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.*
	FERC VSL G1 Violation Severity Level	*The proposed VSL for Requirement R2 does not lower the current level of compliance regarding out of step blocking elements. Out-of-step blocking*

VRF and VSL Justifications for R2		
	Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*elements are addressed in Requirement R1 in PRC-023-1. Out-of-step blocking has been included in a separate requirement in PRC-023-2 per Order 733 and the VSLs for Requirements R1 and R2 are consistent.*
	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 R2 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, R2.*
	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 and VSL Justifications for R3		
R3	Proposed VRF	Medium
	NERC VRF Discussion	*The proposed VRF is consistent with the NERC definition for lower VRF because the proposed requirement requires that 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.. Because the purpose of the requirement is to assure that the recipient entities are aware of, and have agreed with, modified Facility Ratings, this requirement, 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.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *Not applicable. This criteria to which this requirement is related did not exist at the time of the August 14, 2003 Northeast Blackout.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *Not applicable. There are no other requirements in this standard that address similar reliability goals.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *Requirement R2 of FAC-009-1 states that the Transmission Owner and Generator Owner shall each provide Facility Ratings for its solely and jointly owned Facilities that are existing Facilities, new Facilities, modifications to existing Facilities and re-ratings of existing Facilities to its associated Reliability Coordinator(s), Planning Authority(ies), Transmission Planner(s), and Transmission Operator(s) as scheduled by such requesting entities. This data exchange requirement is assigned a Medium VRF.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *Because the purpose of the requirement is to ensure that entities have consistent Facility Ratings in order to operate the BES effectively, this VRF is consistent with the NERC Definition of a Medium VRF.*
	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 and therefore this guideline does not apply.*
	Proposed Lower VSL	*N/A*
	Proposed Moderate VSL	*N/A*
	Proposed High VSL	*N/A*
	Proposed Severe VSL	*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.*

VRF and VSL Justifications for R3		
		OR *The responsible entity did not obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*This VSL is consistent with the VSL assigned to Requirement R2 of approved PRC-023-1, which is essentially identical and is replaced by this requirement.*
	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 VSL is binary and establishes a severe level.* Guideline 2b: *The proposed VSL for Requirement R3 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 R3.*
	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 and VSL Justifications for R4		
R4	Proposed VRF	Lower
	NERC VRF Discussion	*The proposed VRF is consistent with the NERC definition for lower VRF because the proposed requirement requires that each Transmission Owner, Generator Owner, and Distribution Provider that chooses to utilize Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability must provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with a list of circuits associated with those transmission line relays at least once each calendar year, with no more than 15 months between reports. Because the purpose of the requirement is to share information with other entities through the exchange of a report the requirement is considered administrative in nature and consistent with the definition of a lower VRF.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *Not applicable. This criterion to which this requirement is related did not exist at the time of the August 14, 2003 Northeast Blackout.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *Requirement R5 has a similar reliability objective and is assigned a lower VRF.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *Requirement R3 of PRC-015-0 states that the Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days). This data exchange requirement is assigned a Lower VRF.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *Because the purpose of the requirement is to share information with other entities through the exchange of a report the requirement is considered administrative in nature and consistent with the definition of a lower VRF.*
	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 and therefore this guideline does not apply.*
	Proposed Lower VSL	*N/A*
	Proposed Moderate VSL	*N/A*
	Proposed High VSL	*N/A*
	Proposed Severe VSL	*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.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current	*This VLS does not lower the current level of compliance because this is a new Requirement that did not exist in PRC-023-1.*

VRF and VSL Justifications for R4		
	Level of Compliance	
	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 VSL is binary and establishes a severe level.* Guideline 2b: *The proposed VSL for Requirement R4 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 R4.*
	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 and VSL Justifications for R5		
R5	Proposed VRF	Lower
	NERC VRF Discussion	*The proposed VRF is consistent with the NERC definition for lower VRF because the proposed requirement requires that each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide a 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. Because the purpose of the requirement is to share information with other entities through the exchange of a report the requirement is considered administrative in nature and consistent with the definition of a lower VRF.*
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *Not applicable. This criterion to which this requirement is related did not exist at the time of the August 14, 2003 Northeast Blackout.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *Requirement R4 has a similar reliability objective and is also assigned a lower VSL.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *Requirement R3 of PRC-015-0 states that the Transmission Owner, Generator Owner, and Distribution Provider that owns an SPS shall provide documentation of SPS data and the results of studies that show compliance of new or functionally modified SPSs with NERC Reliability Standards and Regional Reliability Organization criteria to affected Regional Reliability Organizations and NERC on request (within 30 calendar days). This data exchange requirement is assigned a Lower VRF.*
	FERC VRF G4 Discussion	Guideline 4- Consistency with NERC Definitions of VRFs *Because the purpose of the requirement is to share information with other entities through the exchange of a report the requirement is considered administrative in nature and consistent with the definition of a lower VRF.*
	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 and therefore this guideline does not apply.*
	Proposed Lower VSL	*N/A*
	Proposed Moderate VSL	*N/A*
	Proposed High VSL	*N/A*
	Proposed Severe VSL	*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.*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	*The proposed VSL for Requirement R5 does not have the unintended consequence of lowering the current level of compliance because PRC-023-1 does not have this requirement as it was added to PRC-023-2.*
	FERC VSL G2	Guideline 2a:

	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	*The proposed VSL is binary and was assigned a severe VSL.* Guideline 2b: *The proposed VSL for Requirement R5 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, R5.*
	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 and VSL Justifications for R6		
R6	Proposed VRF	High
	NERC VRF Discussion	
	FERC VRF G1 Discussion	Guideline 1- Consistency w/ Blackout Report *A High VRF is consistent with the role that relay loadability played in contributing to the August 14, 2003 Northeast Blackout. The Blackout Report identifies examples of sub-200 kV transmission lines tripping due to relay loadability issues, which resulted in cascading outages of higher voltage transmission lines.*
	FERC VRF G2 Discussion	Guideline 2- Consistency within a Reliability Standard *Not applicable. There are no other requirements in this standard that address similar reliability goals.*
	FERC VRF G3 Discussion	Guideline 3- Consistency among Reliability Standards *Not applicable. There are no other standards that address similar reliability goals.*
	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 the Planning Coordinator will evaluate sub-200 kV circuits to determine which such circuits 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. Circuits thus identified will be subject to the other requirements of PRC-023-2.*
	FERC VRF G5 Discussion	Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation *The VRF is consistent with the highest risk reliability objective contained in this requirement.*
	Proposed Lower VSL	*N/A*
	Proposed Moderate VSL	*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 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*

VRF and VSL Justifications for R6		
		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. (part 6.2)
	Proposed High VSL	*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 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)*
	Proposed Severe VSL	*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.* *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 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)*
	FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current	*The proposed VSL for Requirement R6 does not have the unintended consequence of lowering the current level of compliance.* *The currently approved VSL for Requirement R3 of PRC-023-1 gradates the violation of part 3.3 which is now Requirement R6 part 6.2. The proposed VSL gradates this part just as PRC-023-1 does.*

VRF and VSL Justifications for R6		
	Level of Compliance	
	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: *N/A* Guideline 2b: *The proposed VSL for Requirement R6 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, R6.*
	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.*

NERC's VRF Criteria:

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's VRF Guidelines:
VRF G1 – 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. From footnote 15 of the May 18, 2007 Order, FERC's list of critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System includes:

– 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
– Synchronized data recorders
– Clearer criteria for operationally critical facilities

– Appropriate use of transmission loading relief.

VRF G2 – 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.

VRF G3 – 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.

VRF G4 – 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.

VRF G5 –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's Criteria for VSLs:

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

FERC's VSL Guidelines:
VSL G1: 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.)

VSL G2: 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. Avoid using ambiguous terms such as "minor" and "significant" to describe noncompliant performance.)

VSL G3: Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement (VSLs should not expand on what is required in the requirement.)

VSL G4: 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.)

Implementation Plan for PRC-023-2 — Transmission Relay Loadability

1. Standards Involved

- PRC-023-2 —Transmission Relay Loadability

2. Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before the Transmission Relay Loadability standard can be implemented.

3. Proposed Effective Dates

3.1. Requirement R1

3.1.1. For transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above

3.1.1.1. The first day of the first calendar quarter after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first calendar quarter after Board of Trustees adoption, except as noted below.

3.1.1.1.1. For the addition to Requirement R1, criterion 10, to set transformer fault protection relays and transmission line 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, the first day of the first calendar quarter 12 months after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 12 months after Board of Trustees adoption.

3.1.1.1.2. For supervisory elements as described in PRC-023-2 - Attachment A, Section 1.6, the first day of the first calendar quarter 24 months after applicable regulatory approvals, or in those jurisdictions where regulatory approval is not required, the first day of the first calendar quarter 24 months after Board of Trustees adoption.

3.1.1.1.3. For switch-on-to-fault schemes as described in PRC-023-2 - Attachment A, Section 1.3, the 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; or in those jurisdictions where no regulatory approval is required, the later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011.

3.1.2. For circuits identified by the Planning Coordinator pursuant to Requirement R6

3.1.2.1. The 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.

3.2. Requirements R2 and R3

3.2.1. For transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above.

3.2.1.1. The first day of the first calendar quarter after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

3.2.2. For circuits identified by the Planning Coordinator pursuant to Requirement R6

3.2.2.1. The 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.

3.3. Requirements R4 and R5

The first day of the first calendar quarter six months after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees adoption

3.4. Requirement R6

The first day of the first calendar quarter 18 months after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 18 months after Board of Trustees adoption

4. Applicability

4.1. Requirements within the proposed standard apply to the following:

4.1.1. Functional Entity

4.1.1.1. 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).

4.1.1.2. 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).

4.1.1.3. 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.

4.1.1.4. Planning Coordinators

4.1.2. Circuits

4.1.2.1. Circuits Subject to Requirements R1 – R5

4.1.2.1.1. Transmission lines operated at 200 kV and above

4.1.2.1.2. Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator

4.1.2.1.3. Transmission lines operated below 100 kV that are included on a critical facilities list defined by the Regional Entity[1] and selected by the Planning Coordinator in accordance with R6

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

4.1.2.1.5. Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator

4.1.2.1.6. Transformers with low voltage terminals connected below 100 kV that are included on a critical facilities list defined by the Regional Entity and selected by the Planning Coordinator

4.1.2.2. Circuits Subject to Requirement R6

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

4.1.2.2.2. Transmission lines operated below100 kV and transformers with low voltage terminals connected below 100 kV that are included on a critical facilities list defined by the Regional Entity

4.2. Other entities may be recipients of data as described in this standard, but have no requirements placed upon them

5. Implementation Dates

For circuits already identified and subject to the requirements in PRC-023-1, the existing implementation dates will remain in effect.

6. Retired Standards

Requirement R1 of PRC-023-1 is retired the first day of the first calendar quarter after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first calendar quarter after Board of Trustees adoption.

Requirement R2 of PRC-023-1 is retired the first day of the first calendar quarter after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

Requirement R3 of PRC-023-1 is retired the first day of the first calendar quarter 18 months after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 18 months after Board of Trustees adoption.

When all requirements of PRC-023-2 become effective in all jurisdictions as specified above, PRC-023-1 — Transmission Relay Loadability will be retired.

[1] If the Regional Entity has developed such a list.

Implementation Plan for PRC-023-2~~:~~ — Transmission Relay Loadability

1. Standards Involved

- PRC-023-2 —Transmission Relay Loadability

2. Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before the Transmission Relay Loadability standard can be implemented.

3. Proposed Effective ~~Date~~ Dates

3.1. Requirement R1~~: the~~

3.1.1. For transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above

~~2.1.1.1.~~3.1.1.1. The first day of the first calendar quarter after applicable regulatory approval~~s~~, or in those jurisdictions where no regulatory approval is required, the first calendar quarter after Board of Trustees adoption, except as noted below.

~~2.1.1.1.1.~~3.1.1.1.1. For the addition to Requirement R1, criterion 10, to set transformer fault protection relays and transmission line 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, the first day of the first calendar quarter 12 months after applicable regulatory approval~~s~~, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 12 months after Board of Trustees adoption.

~~2.1.1.1.2.~~3.1.1.1.2. For supervisory elements as described in PRC-023-2 - Attachment A, ~~section~~Section 1.6, the first day of the first calendar quarter 24 months after applicable regulatory approval~~s~~, or in those jurisdictions where ~~no~~ regulatory approval is not required, the first day of the first calendar quarter 24 months after Board of Trustees adoption.

3.1.1.1.3. ~~Requirements R2 and R3:~~For switch-on-to-fault schemes as described in PRC-023-2 - Attachment A, Section 1.3, the 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 approval of PRC-023-1; or in those jurisdictions where no regulatory approval is required, the later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011.

3.1.2. For circuits identified by the Planning Coordinator pursuant to Requirement R6

3.1.2.1. The 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.

3.2. Requirements R2 and R3

3.2.1. For transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above.

~~2.1.1.2.~~3.2.1.1. The first day of the first calendar quarter after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

3.2.2. For circuits identified by the Planning Coordinator pursuant to Requirement R6

3.2.2.1. The 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.

3.3. Requirements R4 and R5~~: the~~

The first day of the first calendar quarter six months after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees adoption~~.~~

3.4. Requirement R6~~: the~~

The first day of the first calendar quarter 18 months after applicable regulatory approvals~~ or in those jurisdictions where no regulatory approval is required the first day of the first calendar quarter 18 months after Board of Trustees adoption.~~

~~Requirement R7: the first day of the first calendar quarter after applicable regulatory approvals,~~ or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 18 months after Board of Trustees adoption~~.~~

~~3.~~4. Applicability

~~3.1.~~4.1. Requirements within the proposed standard apply to~~:~~ the following:

~~3.1.1.~~4.1.1. ~~4.1.~~ **Functional ~~Entities:~~Entity**

~~3.1.1.1.~~4.1.1.1. ~~4.1.1~~ Transmission Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to ~~facilities~~circuits defined in 4.2.1 ~~through 4.2.6.~~(Circuits Subject to Requirements R1 – R5).

~~3.1.1.2.~~4.1.1.2. ~~4.1.2~~ Generator Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to ~~facilities~~circuits defined in 4.2.1 ~~through 4.2.6.~~(Circuits Subject to Requirements R1 – R5).

~~3.1.1.3.~~4.1.1.3. ~~4.1.3~~ Distribution Providers with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied ~~according~~ to ~~facilities~~circuits defined in 4.2.1 ~~through 4.2.6,~~(Circuits Subject to Requirements R1 – R5), provided those ~~facilities~~circuits have bi-directional flow capabilities.

~~3.1.1.4.~~4.1.1.4. ~~4.1.4~~ Planning Coordinators

~~4.2. Facilities:~~

4.1.2. ~~4.2.1~~ Circuits

4.1.2.1. Circuits Subject to Requirements R1 – R5

~~3.1.1.4.1.~~4.1.2.1.1. Transmission lines operated at 200 kV and above~~.~~

~~3.1.1.4.2.~~4.1.2.1.2. ~~4.2.2~~ Transmission lines operated at 100 kV to 200 kV ~~that~~selected by the Planning Coordinator ~~has determined are required to comply with this standard.~~

~~3.1.1.4.3.~~4.1.2.1.3. ~~4.2.3~~ Transmission lines operated below 100 kV that ~~Regional Entities have identified as~~are included on a critical facilities ~~for the purposes of~~list defined by the ~~Compliance Registry~~Regional Entity[1] and selected by the Planning Coordinator ~~has determined are required to comply with this standard.~~ in accordance with R6

~~3.1.1.4.4.~~4.1.2.1.4. ~~4.2.4~~ Transformers with low voltage terminals connected at 200 kV and above~~.~~

~~3.1.1.4.5.~~4.1.2.1.5. ~~4.2.5~~ Transformers with low voltage terminals connected at 100 kV to 200 kV ~~that~~selected by the Planning Coordinator ~~has determined are required to comply with this standard.~~

~~3.1.1.4.6.~~4.1.2.1.6. ~~4.2.6~~ Transformers with low voltage terminals connected below 100 kV that ~~Regional Entities have identified as~~are included on a critical facilities ~~for~~list defined by the ~~purposes of the Compliance Registry~~Regional Entity and selected by the Planning Coordinator ~~has determined are required to comply with this standard~~

4.1.2.2. Circuits Subject to Requirement R6

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

4.1.2.2.2. Transmission lines operated below100 kV and transformers with low voltage terminals connected below 100 kV that are included on a critical facilities list defined by the Regional Entity

~~3.2.~~4.2. Other entities may be recipients of data as described in this standard, but have no requirements placed upon them~~.~~

5. Implementation Dates

For circuits already identified and subject to the requirements in PRC-023-1, the existing implementation dates will remain in effect.

~~4.~~6. Retired Standards

~~The following standard will be retired when PRC-023-2 becomes effective:~~

-

[1] If the Regional Entity has developed such a list.

Requirement R1 of PRC-023-1 is retired the first day of the first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first calendar quarter after Board of Trustees adoption.

Requirement R2 of PRC-023-1 is retired the first day of the first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

Requirement R3 of PRC-023-1 is retired the first day of the first calendar quarter 18 months after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 18 months after Board of Trustees adoption.

When all requirements of PRC-023-2 become effective in all jurisdictions as specified above, PRC-023-1 — Transmission Relay Loadability will be ~~completely retired once PRC-023-2 becomes effective as specified above.~~ retired.

Standard Development Roadmap

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

Development Steps Completed:

1. The Standards Committee approved the SAR for posting on August 12, 2010.
2. SAR posted for formal comment on August 19, 2010.
3. Standard posted for informal comment period on August 19, 2010.
4. Attachment B (Applicability Test) of standard posted for informal comment period on September 23, 2010.
5. Standard with applicability test posted for 45-day formal comment period with concurrent ballot during the last 10 days of the comment period on November 1, 2010.

Proposed Action Plan and Description of Current Draft:

This is the third draft of the standard developed to address the FERC directives in Order No. 733 and is posted for a 20-day successive ballot period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop third draft of the standard and respond to comments	December 2010 – January 2011
2. Conduct successive ballot and recirculation ballot of standard	January 2011- February 2011
3. Submit to NERC Board of Trustees for approval to file	February 2011
4. File standard with FERC for approval	March 2011

A. Introduction

1. **Title: Transmission Relay Loadability**

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

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 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

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.

4.2.1.3 Transmission lines operated below 100 kV that are included on a critical facilities list defined by the Regional Entity[1] 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.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that are included on a critical facilities list defined by the Regional Entity 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

[1] If the Regional Entity has developed such a list.

4.2.2.2 Transmission lines operated below100 kV and transformers with low voltage terminals connected below 100 kV that are included on a critical facilities list defined by the Regional Entity

5. Effective Dates

5.1. Requirement R1

5.1.1 For transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above.

5.1.1.1 The first day of the first calendar quarter after applicable regulatory approval or in those jurisdictions where no regulatory approval is required, the first calendar quarter after Board of Trustees adoption, except as noted below.

5.1.1.1.1 For the addition to Requirement R1, criterion 10, to set transformer fault protection relays and transmission line 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, the first day of the first calendar quarter 12 months after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 12 months after Board of Trustees adoption.

5.1.1.1.2 For supervisory elements as described in PRC-023-2 - Attachment A, Section 1.6, the first day of the first calendar quarter 24 months after applicable regulatory approvals, or in those jurisdictions where regulatory approval is not required, the first day of the first calendar quarter 24 months after Board of Trustees adoption.

5.1.1.1.3 For switch-on-to-fault schemes as described in PRC-023-2 - Attachment A, Section 1.3, the later of the first day of the first calendar quarter after applicable regulatory approval of PRC-023-2 or the first day of the first calendar quarter 39 months following applicable regulatory approval of PRC-023-1; or in those jurisdictions where no regulatory approval is required, the later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011.

5.1.2 For circuits identified by the Planning Coordinator pursuant to Requirement R6

5.1.2.1 The 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.

5.2. Requirements R2 and R3

5.2.1 For transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above.

5.2.1.1 The first day of the first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

5.2.2 For circuits identified by the Planning Coordinator pursuant to Requirement R6

5.2.2.1 The 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.

5.3. Requirements R4 and R5

The first day of the first calendar quarter six months after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees adoption.

5.4. Requirement R6

The first day of the first calendar quarter 18 months after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 18 months after Board of Trustees adoption.

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.

[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.

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.

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].

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

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 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 per application of Attachment B, including identification of the first calendar year in which any criterion in 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 or a list of incremental 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 or a list of incremental 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 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

- 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 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. OR

Requirement	Lower	Moderate	High	Severe
				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 than 15 months and less than 24 months lapsed between assessments.	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 months or more lapsed between assessments.	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. OR The Planning Coordinator used the criteria established within Attachment B, at least once each

Requirement	Lower	Moderate	High	Severe
		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. (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 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)	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 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

Requirement	Lower	Moderate	High	Severe
				provided the list more than 60 days after the list was established or updated. (part 6.2)

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, January 9, 2007, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/~filez/reports.html.

Version History

Version	Date	Action	Change Tracking
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	
2	November 1, 2010	Revised to address directives from Order 733	
2	January 14, 2011	Revised to address formal industry comments	

PRC-023 — 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. Supervisory elements associated with current-based, communication-assisted schemes 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 — 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.
- Lines operated below100 kV and transformers with low voltage terminals connected below 100 kV that are included on a critical facilities list defined by the Regional Entity.

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 plant owner 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.

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[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.

Standard Development Roadmap

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

Development Steps Completed:

1. The Standards Committee approved the SAR for posting on August 12, 2010.
2. SAR posted for formal comment on August 19, 2010.
3. Standard posted for informal comment period on August 19, 2010.
4. Attachment B (Applicability Test) of standard posted for informal comment period on September 23, 2010.
5. Standard with applicability test posted for 45-day formal comment period with concurrent ballot during the last 10 days of the comment period on November 1, 2010.

Proposed Action Plan and Description of Current Draft:

This is the ~~second~~third draft of the standard developed to address the FERC directives in Order No. 733 and is posted for a ~~45~~20-day ~~formal comment period with concurrent~~successive ballot ~~during the last 10 days of the comment~~ period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Develop third draft of the standard and respond to comments~~.~~	December 2010 – January 2011
2. Conduct successive ballot and recirculation ballot of standard	January 2011- February 2011
3. Submit to NERC Board of Trustees for approval to file	February 2011
4. ~~Submit~~File standard ~~to~~with FERC for approval	March 2011

A. Introduction

1. **Title: Transmission Relay Loadability**
2. **Number:** PRC-023-2
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~~faults.
4. **Applicability~~:~~**

4.1. Functional ~~Entities:~~Entity

4.1.1 Transmission Owners with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to ~~facilities~~circuits defined in 4.2.1 ~~through 4.2.6.~~*(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 ~~facilities~~circuits defined in 4.2.1 ~~through 4.2.6.~~*(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 ~~according~~ to ~~facilities~~circuits defined in 4.2.1 ~~through 4.2.6,~~*(Circuits Subject to Requirements R1 – R5),* provided those ~~facilities~~circuits have bi-directional flow capabilities.

4.1.4 Planning Coordinators

~~**4.2. Facilities:**~~

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 ~~that~~selected by the Planning Coordinator ~~has determined are required to comply with this standard~~.

4.2.1.3 Transmission lines operated below 100 kV that ~~Regional Entities have identified as~~are included on a critical facilities ~~for~~list defined by the ~~purposes of the Compliance Registry~~Regional Entity[1] and selected by the Planning Coordinator ~~has determined are required to comply with this standard~~in accordance with R6.

~~FERC Order 733, ¶60: Apply an "add in" approach to sub-100 kV facilities.~~

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 ~~that~~selected by the Planning Coordinator ~~has determined are required to comply with this standard~~.

[1] If the Regional Entity has developed such a list.

4.2.1.6 Transformers with low voltage terminals connected below 100 kV that ~~Regional Entities have identified as~~are included on a critical facilities ~~for~~list defined by the ~~purposes of the Compliance Registry~~ Regional Entity and selected by the Planning Coordinator ~~has determined are required to comply~~in accordance with ~~this standard~~R6.

4.2.2 Circuits Subject to Requirement R6

~~FERC Order 733, ¶284: Remove the exceptions footnote from the "Effective Dates" section.~~

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 below100 kV and transformers with low voltage terminals connected below 100 kV that are included on a critical facilities list defined by the Regional Entity

5. Effective Dates~~:~~

5.1. Requirement R1~~: the~~

5.1.1 For transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above.

5.1.1.1 The first day of the first calendar quarter after applicable regulatory ~~approvals~~approval or in those jurisdictions where no regulatory approval is required, the first calendar quarter after Board of Trustees adoption, except as noted below.

5.1.1.1.1 For the addition to Requirement R1, criterion 10, to set transformer fault protection relays and transmission line 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, the first day of the first calendar quarter 12 months after applicable regulatory ~~approvals~~approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 12 months after Board of Trustees adoption.

5.1.1.1.2 For supervisory elements as described in PRC-023-2 - Attachment A, ~~section~~Section 1.6, the first day of the first calendar quarter 24 months after applicable regulatory approvals, or in those jurisdictions where regulatory approval is not required, the first day of the first calendar quarter 24 months after Board of Trustees adoption.

5.1.1.1.3 ~~Requirements R2 and R3:~~For switch-on-to-fault schemes as described in PRC-023-2 - Attachment A, Section 1.3, the later of the first day of the first calendar quarter after applicable regulatory ~~approvals~~approval of PRC-023-2 or the first day of the first calendar quarter 39 months following applicable regulatory approval of PRC-023-1; or in those jurisdictions where no regulatory approval is required, the later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011.

5.1.2 ~~Requirements R4 and R5: the first day of the first calendar quarter six months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required the first~~ For circuits identified by the Planning Coordinator pursuant to Requirement R6

~~5.2.~~ The later of the first day of the first calendar quarter ~~six~~39 months ~~after Board of Trustees adoption.~~

~~5.2.1.1~~5.1.2.1 ~~Requirement R6:~~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 ~~quarter 18 months after applicable regulatory approvals or in those jurisdictions where no regulatory approval is required the first day of the first calendar quarter 18 months after Board of Trustees adoption.~~ year in which any criterion in Attachment B applies.

5.2. ~~Requirement R7: the~~**Requirements R2 and R3**

5.2.1 For transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above.

~~5.2.1.2~~5.2.1.1 The first day of the first calendar quarter after applicable regulatory ~~approvals~~approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

5.2.2 For circuits identified by the Planning Coordinator pursuant to Requirement R6

5.2.2.1 The 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.

5.3. Requirements R4 and R5

The first day of the first calendar quarter six months after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees adoption.

5.4. Requirement R6

The first day of the first calendar quarter 18 months after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 18 months after Board of Trustees adoption.

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] [~~Mitigation~~ 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.

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 ~~such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability and~~ so that the relays do not operate at or below the greater of:

~~FERC Order 733, ¶203: Modify sub-requirement R1.10 to verify equipment is capable of sustaining the anticipated overload associated with the fault.~~

[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.

- 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.

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 ~~verify that~~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]*

~~FERC Order 733, ¶244: Include section 2 of Appendix A as an additional Requirement.~~

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

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 ~~a~~an updated list of ~~facilities~~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]*

~~FERC Order 733, ¶186: Modify R1.2 to require that TOs, GOs, and DPs give their TOPs a list of transmission facilities that implement R1.2.~~

R5. Each Transmission Owner, Generator Owner, and Distribution Provider that sets transmission line relays according to Requirement R1 criterion 12 shall provide ~~a~~an updated list of the ~~facilities~~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 ~~entities~~the ERO to ~~know which facilities~~ compile a list of all circuits that have protective relay settings that limit ~~the facility's~~circuit capability. *[Violation Risk Factor: Lower] [Time Horizon: Long Term Planning]*

~~FERC Order 733, ¶224: Make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant sub-requirement R1.12.of anticipated overload.~~

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

~~**6.1** Apply the criteria to transmission lines that are operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV.~~

~~**6.2** Apply the criteria to transmission lines operated below 100 kV and transformers with low voltage terminal connections below 100 kV, if the Regional Entity has identified either of these Element types as critical facilities for the purposes of the Compliance Registry and they are in its Planning Coordinator Area.~~

~~**6.3**~~ Maintain a list of ~~facilities determined according to the process described in Requirement R6.~~

~~6.4~~6.1 ~~Include on the list the~~circuits subject to PRC-023-2 per application of Attachment B, including identification of the first calendar year ~~studied for~~in which any criterion ~~B4~~ in Attachment B ~~first applies when a facility is added and only criterion B4 is applicable~~applies.

~~FERC Order 733, ¶237: Modify sub-requirement R3.3 to add the RE to list of entities that receive the critical facilities list.~~

~~6.5~~6.2 Provide ~~a~~the list of ~~facilities~~circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator ~~Area~~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, Generator Owner, and Distribution Provider shall implement Requirement R1, Requirement R2, Requirement R3, Requirement R4, and Requirement R5 for each facility that is added to the Planning Coordinator's list of facilities that must comply with this standard pursuant to Requirement R6, Part 6.5 by the later of the first day of the second calendar quarter 24 months following notification by the Planning Coordinator of a facility's inclusion on such a list or the first day of the first calendar quarter of the year in which Attachment B criterion B4 first applies. *[Violation Risk Factor: High] [Time Horizon: Long Term Planning]*~~

C. Measures

M1. ~~The~~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. ~~The~~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 ~~allows~~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. ~~The~~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 ~~they~~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. ~~The~~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 ~~they~~it provided its Planning Coordinator, Transmission Operator, and Reliability Coordinator with ~~a~~an updated list of ~~facilities~~circuits associated with those transmission line relays within the required timeframe. The updated list may either be a full list or a list of incremental changes to the previous list. (R4)

M5. ~~The~~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 ~~a~~an updated list of the ~~facilities~~circuits associated with those relays to its Regional Entity within the required timeframe. The updated list may either be a full list or a list of incremental changes to the previous list. (R5)

M6. ~~The~~Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that ~~they~~it used the criteria established within Attachment B to determine the ~~facilities that~~circuits in its Planning Coordinator area for which applicable entities must comply with ~~this~~the standard as described in Requirement R6. The Planning Coordinator shall have a dated list of such ~~facilities~~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.~~ area within the required timeframe. (R6)

~~**M7.** The Transmission Owner, Generator Owner, and Distribution Provider shall have evidence such as dated spreadsheets, summaries of calculations, and study reports, that it implemented the Requirements within the specified timeframe per Requirement R7.~~

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

~~Regional Entity~~

- 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 ~~and R7~~ 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 ~~facilities that are critical to the reliability of the electric system~~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 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. OR

Requirement	Lower	Moderate	High	Severe
				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, ~~Regional Entity,~~ and Reliability Coordinator with ~~a~~an updated list of ~~facilities~~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 ~~a~~an updated list of ~~facilities~~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 ~~which transmission Elements, described in 6.1 and 6.2,~~the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.~~3 through~~1 and 6.~~5~~2, but more than 15 months and less than	The Planning Coordinator used the criteria established within Attachment B to determine ~~which transmission Elements, described in 6.1 and 6.2,~~the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met parts 6.~~3 through~~1 and 6.~~5~~2, but 24 months or more lapsed between	The Planning Coordinator failed to use the criteria established within Attachment B to determine ~~which transmission Elements, described in 6.1 and 6.2,~~the circuits in its Planning Coordinator area for which applicable entities must comply with the standard. OR

Requirement	Lower	Moderate	High	Severe
		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 ~~which transmission Elements, described in 6.1 and 6.2,~~the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.~~3~~1 and 6.~~5~~2 but failed to include the calendar year ~~studied for~~in which any criterion ~~B4~~ in Attachment B first applies~~ when a facility is added and only criterion B4 is applicable (part 6.4).~~. 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 ~~which transmission Elements, described in 6.1 and 6.2,~~the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.~~3~~1 and 6.~~4~~2 but provided the list of ~~facilities~~circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and	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 ~~which transmission Elements, described in 6.1 and 6.2,~~the circuits in its Planning Coordinator area for which applicable entities must comply with the standard and met 6.~~3~~1 and 6.~~4~~2 but provided the list of ~~facilities~~circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator ~~Area within~~area between 46 days and 60 days after list was established or updated. (part 6.~~5).~~2)	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 ~~which transmission Elements, described in 6.1 and 6.2,~~the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to meet parts 6.~~3, 6.4~~1 and 6.~~5~~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 ~~which transmission Elements~~the circuits in its Planning Coordinator area for which applicable entities must comply with the standard but failed to ~~apply the criteria~~maintain the list of circuits determined according to the ~~Elements~~process described in ~~parts~~Requirement R6. (part 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 ~~which transmission Elements, described in 6.1 and 6.2,~~the circuits in its Planning

Requirement	Lower	Moderate	High	Severe
		Distribution Providers within its Planning Coordinator ~~Area within 31days~~ area between 31 days and 45 days after the list was established or updated. (part 6.~~5).~~2)		Coordinator area for which applicable entities must comply with the standard and met 6.~~4 and 6.5 but failed to maintain the list of facilities determined according to the process described in Requirement R6 (part 6.3).~~ ~~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 which transmission Elements, described in 6.1 and 6.2, in its Planning Coordinator area must comply with the standard and met 6.3 and 6.4~~1 but failed to provide the list of ~~facilities~~circuits to the Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within its Planning Coordinator ~~Area~~ area or provided the list more than 60 days after the list was established or updated. (part 6.~~5).~~2)
~~R7~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Owner, Generator Owner, or Distribution Provider failed to implement Requirement R1, Requirement R2, Requirement R3, Requirement R4, and Requirement R5 for each facility that is added to the Planning Coordinator's list of facilities that must comply with this standard pursuant to Requirement R6, Part 6.5 by the~~

Requirement	Lower	Moderate	High	Severe
				~~later of the first day of the second calendar quarter after 24 months following notification by the Planning Coordinator of a facility's inclusion on such a list by the Planning Coordinator or the first day of the first calendar quarter of the year in which Attachment B criterion B4 first applies.~~

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, January 9, 2007, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/~filez/reports.html.

Version History

Version	Date	Action	Change Tracking
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	
2	November 1, 2010	Revised to address directives from Order 733	
2	January 14, 2011	Revised to address formal industry comments	

PRC-023 — 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. Supervisory elements associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications.

~~FERC Order 733, ¶264: Revise section 1 of Attachment A to include supervising relay elements.~~

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 — Attachment B

~~FERC Order 733, ¶69: Specify the test that PCs must use to determine whether sub-200 kV facility is critical to reliability of the BES~~

~~**Criteria**~~

~~Review each applicable circuit against the criteria in this Attachment to determine the facilities that must comply with the standard.~~

~~Applicable circuits include:~~

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~~Lines operated below100 kV and transformers with low voltage terminals connected below 100 kV that ~~Regional Entities have identified as~~ are included on a critical facilities ~~for~~ list defined by the ~~purposes of the Compliance Registry~~Regional Entity.

Criteria

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

B1. ~~Each~~The circuit ~~that~~ is a monitored ~~Element~~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 ~~Element~~Facility in the ~~Texas Interconnection or~~ Québec Interconnection, that has been included to address ~~long-term~~ reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator.

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

B3. ~~Each~~The circuit ~~that~~ forms a path (as agreed to by the plant owner and the ~~Transmission Entity~~transmission entity) to supply off-site power to a nuclear ~~plants.~~ plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.

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

a. Simulate double contingency combinations selected by engineering judgment ~~in TPL-003 Category C3, but~~, 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.

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

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 ~~as a~~of the circuit~~ that must comply with the standard~~ 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. ~~Radial~~Radially operated circuits serving only load are excluded.

B5. ~~Each~~The circuit ~~that~~is selected by the Planning Coordinator ~~may include~~ based on ~~other~~ 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-~~1~~2

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 with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to ~~facilities~~circuits defined ~~below:~~ 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

4.2. Circuits

4.2.1 Circuits Subject to Requirements R1 – R5

~~4.1.1.1~~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 ~~as designated~~selected by the Planning Coordinator~~ as~~.

~~4.1.1.2~~4.2.1.3 Transmission lines operated below 100 kV that are included on a critical ~~to~~facilities list defined by the ~~reliability of~~Regional Entity[1] and selected by the ~~Bulk Electric System.~~Planning Coordinator in accordance with R6.

~~4.1.1.3~~4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

~~4.1.1.4~~4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV ~~as designated~~selected by the Planning Coordinator~~ as critical to the reliability of the Bulk Electric System~~.

4.2.1.6 ~~Generator Owners~~Transformers with ~~load-responsive phase~~ low voltage terminals connected below 100 kV that are included on a critical facilities list defined by the Regional Entity 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

[1] If the Regional Entity has developed such a list.

4.2.2.2 Transmission lines operated below100 kV and transformers with low voltage terminals connected below 100 kV that are included on a critical facilities list defined by the Regional Entity

5. Effective Dates

5.1. Requirement R1

5.1.1 For transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above.

5.1.1.1 The first day of the first calendar quarter after applicable regulatory approval or in those jurisdictions where no regulatory approval is required, the first calendar quarter after Board of Trustees adoption, except as noted below.

5.1.1.1.1 For the addition to Requirement R1, criterion 10, to set transformer fault protection ~~systems~~relays and transmission line 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, the first day of the first calendar quarter 12 months after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 12 months after Board of Trustees adoption.

~~4.1.1.4.1~~5.1.1.1.2 For supervisory elements as described in PRC-023-2 - Attachment A, ~~applied to facilities defined in 4.~~Section 1.~~1 through 4.1.4~~6, the first day of the first calendar quarter 24 months after applicable regulatory approvals, or in those jurisdictions where regulatory approval is not required, the first day of the first calendar quarter 24 months after Board of Trustees adoption.

~~**4.2.** Distribution Providers with load-responsive phase protection systems~~For switch-on-to-fault schemes as described in PRC-023-2 - Attachment A, ~~applied according to facilities defined in 4.1.1 through 4.1.4., provided that those facilities have bi-directional flow capabilities.~~

~~**4.3.** Planning Coordinators.~~

~~**5. Effective Dates**[2]**:**~~

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

~~**5.1.1** For circuits described in 4.1.1 and 4.~~Section 1.3~~above (except for switch-on-to-fault schemes) —~~, the ~~beginning~~later of the first day of the first calendar quarter ~~following~~after applicable regulatory ~~approvals.~~

~~5.1.1.1.1~~5.1.1.1.3 ~~For circuits described in 4.1.~~approval of PRC-023-2 ~~and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning~~or the first day of the first calendar quarter 39 months following applicable regulatory ~~approvals.~~ approval of PRC-023-1; or in those jurisdictions where no regulatory approval is required, the later of the first day of the

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

first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011.

5.1.2 ~~Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its~~ For circuits identified by the Planning Coordinator pursuant to ~~R3.3 to comply with R1 (including all sub-requirements) for each facility that is added to~~Requirement R6

5.1.2.1 The later of the first day of the first calendar quarter 39 months following notification by the Planning ~~Coordinator's critical facilities list determined~~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.

5.2. Requirements R2 and R3

5.2.1 For transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above.

5.2.1.1 The first day of the first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

~~5.1.2~~5.2.2 For circuits identified by the Planning Coordinator pursuant to ~~R3.1.~~Requirement R6

~~5.2. Requirement 3: 18 months following applicable regulatory approvals.~~

5.2.2.1 ~~Requirements~~The 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.

5.3. Requirements R4 and R5

The first day of the first calendar quarter six months after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees adoption.

5.4. Requirement R6

The first day of the first calendar quarter 18 months after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 18 months after Board of Trustees adoption.

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1~~.~~, criteria 1 through ~~R1.~~13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the ~~Bulk Electric System~~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] [~~Mitigation~~ 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[3] 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 ~~R1.~~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.
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 ~~they~~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.

[3] 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 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[4].

11. For transformer overload protection relays that do not comply with ~~R1.~~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~~. The protection must allow this overload~~, for at least 15 minutes to ~~allow~~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~~. The setting should be~~ set no less than 100° C for the top oil ~~or~~temperature or no less than 140° C for the winding hot spot temperature[5].

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~~.2~~ 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. ~~The~~Each Transmission Owner, Generator Owner, ~~or~~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]*

~~**R2.**~~**R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in ~~R1.~~Requirement R1, criterion 6, ~~R1.~~7, ~~R1.~~8, ~~R1.~~9, ~~R1.~~12, or ~~R1.~~13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

[4] 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

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

~~R3.~~R4. ~~The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV~~Each Transmission Owner, Generator Owner, and Distribution Provider that ~~must meet~~chooses to use Requirement ~~1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission~~ 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: ~~Medium~~Lower] [Time Horizon: Long Term Planning]*

R5. ~~The~~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]*

~~1.1~~ Each Planning Coordinator shall ~~have a process~~conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in Attachment B to determine the ~~facilities that are critical to the reliability of the Bulk Electric System.~~

~~1.3.1 This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.~~

~~1.2 The~~circuits in its Planning Coordinator ~~shall maintain a current list of facilities determined according to the process described in R3.1.~~

R6. ~~The~~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* ~~Coordinator shall provide a list of facilities to its~~*]*

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

~~6.3~~6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within ~~30~~its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to ~~the~~that list.

C. Measures

M1. ~~The~~Each Transmission Owner, Generator Owner, and Distribution Provider shall ~~each~~ have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays ~~are~~is set according to one of the criteria in ~~R1.~~Requirement R1, criterion 1 through ~~R1.~~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)

~~M1.~~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)

~~M2.~~M3. ~~The~~Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to ~~the criteria in~~ Requirement R1~~.~~, criterion 6, ~~R1.~~7, ~~R1.~~8, ~~R1.~~9, ~~R1.~~12, or ~~R.~~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. (~~R2~~R3)

M4. ~~The~~ 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 ~~shall have~~, 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 ~~documented process for the determination of facilities as described in R3~~full list or a list of incremental 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 or a list of incremental changes to the previous list. (R5)

~~M3.~~M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it 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 as described in Requirement R6. The Planning Coordinator shall have a ~~current~~dated list of such ~~facilities~~circuits and shall have evidence such as dated correspondence that it provided the list to the ~~approriate~~Regional Entities, Reliability Coordinators, Transmission ~~Operators~~Owners, Generator ~~Operators~~Owners, and Distribution Providers~~. (R3~~ within its Planning Coordinator area within the required timeframe. (R6)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

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

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

~~One calendar year.~~

- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

~~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 ~~R3~~R6. The Planning Coordinator shall retain the most recent list of ~~facilities that are critical to~~ circuits in its Planning Coordinator area for which applicable entities must comply with the ~~reliability of the electric system~~standard, as determined per ~~R3~~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 shall ~~retain its compliance documentation for three years~~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

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

None.

2. **Violation Severity Levels:**

~~R#~~Requirement	Lower	Moderate	High	Severe
R1	N/A	~~Evidence that relay settings comply with criteria in R1.1 though 1.13 exists, but evidence is incomplete or incorrect for one or more of the subrequirements.~~ N/A	N/A	~~Relay settings do not comply with any of the sub requirements R1.1 through R1.13~~ ~~OR~~ ~~Evidence does not exist to support that relay settings comply with one of the criteria in subrequirements R1.1 through R1.13.~~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

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~~R#~~Requirement	Lower	Moderate	High	Severe
				per Requirement R1.
~~R2~~R3	~~Criteria described in R1.6, R1.7. R1.8. R1.9, R1.12, or R.13 was used but evidence does not exist that agreement was obtained in accordance with R2.~~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. 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.

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~~R#~~Requirement	Lower	Moderate	High	Severe
~~R3~~R6	N/A	~~Provided the list of facilities critical~~The Planning Coordinator used the criteria established within Attachment B to determine the ~~reliability of~~circuits in its Planning Coordinator area for which applicable entities must comply with the ~~Bulk Electric System~~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 ~~the appropriate~~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	~~Provided the list of facilities critical~~The Planning Coordinator used the criteria established within Attachment B to determine the ~~reliability of~~circuits in its Planning Coordinator area for which applicable entities must comply with the ~~Bulk Electric System~~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 ~~the appropriate~~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)	~~Does not have a process in place to determine facilities that are critical to the reliability of the Bulk Electric System.~~ 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. OR ~~Does not maintain a current list of facilities critical to the reliability of the Bulk Electric System,~~ ~~OR~~ ~~Did not~~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

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~~R#~~Requirement	Lower	Moderate	High	Severe
		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. (part 6.2)		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 6.1 but failed to provide the list of ~~facilities critical to the reliability of the Bulk Electric System to the appropriate~~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)

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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, January 9, 2007, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com/~filez/reports.html.

Version History

Version	Date	Action	Change Tracking
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	
2	November 1, 2010	Revised to address directives from Order 733	

PRC-023 — Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
   - **1.1.** Phase distance.
   - **1.2.** Out-of-step tripping.
   - **1.3.** Switch-on-to-fault.
   - **1.4.** Overcurrent relays.
   - **1.5.** Communications aided protection schemes including but not limited to:
     - **1.5.1** Permissive overreach transfer trip (POTT).
     - **1.5.2** Permissive under-reach transfer trip (PUTT).
     - **1.5.3** Directional comparison blocking (DCB).
     - **1.5.4** Directional comparison unblocking (DCUB).

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

   - **1.6.** Supervisory elements associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications.

~~3.~~2. The following protection systems are excluded from requirements of this standard:
   - ~~3.1.~~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
   - ~~3.2.~~2.2. Protection systems intended for the detection of ground fault conditions.
   - ~~3.3.~~2.3. Protection systems intended for protection during stable power swings.
   - ~~3.4.~~2.4. Generator protection relays that are susceptible to load.
   - ~~3.5.~~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.
   - ~~3.6.~~2.6. Protection systems that are designed only to respond in time periods which allow ~~operators~~ 15 minutes or greater to respond to overload conditions.
   - ~~3.7.~~2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.
   - ~~3.8.~~2.8. Relay elements associated with ~~DC~~dc lines.
   - ~~3.9.~~2.9. Relay elements associated with ~~DC~~dc converter transformers.

PRC-023 — 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.
- Lines operated below100 kV and transformers with low voltage terminals connected below 100 kV that are included on a critical facilities list defined by the Regional Entity.

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 plant owner 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[6] 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.

[6] 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.

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Standards Announcement

Successive Ballot and Non-binding Poll Open
Project 2010-13 – Relay Loadability Order 733 Modifications
January 24-February 13, 2011

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2010-13: Revisions to Relay Loadability for Order 733

PRC-023-2 — Transmission Relay Loadability has been posted for a 20-day successive ballot of the proposed standard and its associated implementation plan through **8 p.m. on February 13, 2011**. A non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) will be conducted during the same time.

Registered Ballot Body members who joined the ballot pool to vote on the standard have already been automatically entered in a separate pool to participate in the non-binding poll for the VRFs and VSLs. For ballot pool members, the non-binding poll appears in the list of current ballots, and is labeled accordingly.

Instructions

Members of the ballot pools associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Background

This standard was revised to address a set of directives in Order 733 and must be submitted to FERC by March 18, 2011. To meet this delivery date, the Standards Committee authorized use of the expedited standard development process. Under the expedited standard development process, the Standards Committee may alter certain steps in the standard development process to meet a regulatory deadline. In this case, the Standards Committee authorized the drafting team to conduct successive ballots without parallel comment periods. To allow stakeholders time to review the changes made between ballots, the Standards Committee authorized an extended ballot window of 20 calendar days, rather than 10 calendar days.

Next Steps

Voting results will be posted and announced after the ballot windows close.

Project Background

When FERC issued Order 733, approving PRC-023-1 —Transmission Relay Loadability, it directed several changes to that standard and also directed development of one or more new standards within specified time periods. NERC filed for clarification and rehearing, asking for clarity and an extension of time to address the directives; however, without a response to the requests for clarification and rehearing, NERC must proceed as though these requests will be denied.

The SAR for Project 2010-13 subdivides the standard-development-related directives into three phases. Phase I

addresses the specific directives from Order 733 that identified required modifications to various elements within PRC-023-1. Phase II addresses directives associated with development of a new standard to address generator relay loadability. Phase III addresses directives associated with writing requirements to address protective relay operations due to power swings.

More information on this project may be found on the project page:

http://www.nerc.com/filez/standards/SAR_Project%202010-13_Order%20733%20Relay%20Modifiations.html

Standards 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 Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

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Ballot Name:	2010-13 Relay Loadability Order Non-Binding Poll
Ballot Period:	1/24/2011 - 2/14/2011
Total # Opinions:	173
Total Ballot Pool:	324
Summary Results:	80% of those who registered to participate provided an opinion; 65% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed.

Individual Ballot Pool Results

Segment	Organization	Member	Opinion	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Affirmative	
1	American Electric Power	Paul B. Johnson	Negative	View
1	American Transmission Company, LLC	Andrew Z Pusztai		
1	APS	Barbara McMinn		
1	Arizona Public Service Co.	Robert D Smith	Abstain	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott Kinney	Affirmative	
1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Beaches Energy Services	Joseph S. Stonecipher	Negative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Abstain	
1	CenterPoint Energy	Paul Rocha	Negative	
1	Central Maine Power Company	Kevin L Howes	Abstain	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	

1	City of Vero Beach	Randall McCamish	Negative	View
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Commonwealth Edison Co.	Gregory Campbell		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Abstain	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Abstain	
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Abstain	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Negative	View
1	Georgia Transmission Corporation	Harold Taylor, II	Negative	View
1	Great River Energy	Gordon Pietsch	Negative	View
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	
1	Idaho Power Company	Ronald D. Schellberg		
1	International Transmission	Michael Moltane	Affirmative	

	Company Holdings Corp			
1	Kansas City Power & Light Co.	Michael Gammon	Abstain	
1	Keys Energy Services	Stan T. Rzad	Negative	View
1	Lake Worth Utilities	Walt Gill	Negative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	View
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Richard Burt	Negative	View
1	National Grid	Saurabh Saksena	Affirmative	View
1	Nebraska Public Power District	Richard L. Koch	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura		
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Omaha Public Power District	Douglas G Peterchuck	Affirmative	
1	Oncor Electric Delivery	Michael T. Quinn	Negative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas		

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1	PacifiCorp	Colt Norrish	Affirmative	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Puget Sound Energy, Inc.	Catherine Koch		
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Abstain	
1	Santee Cooper	Terry L. Blackwell	Negative	
1	SCE&G	Henry Delk, Jr.	Abstain	
1	Seattle City Light	Pawel Krupa	Abstain	
1	Sierra Pacific Power Co.	Rich Salgo	Abstain	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon	Abstain	
1	Southern California Edison Co.	Dana Cabbell	Negative	
1	Southern Company Services, Inc.	Horace Stephen Williamson		
1	Southern Illinois Power Coop.	William G. Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	

1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Abstain	
1	Texas Municipal Power Agency	Frank J. Owens	Abstain	
1	Transmission Agency of Northern California	James W. Beck	Abstain	
1	Tri-State G & T Association, Inc.	Keith V Carman	Negative	
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Abstain	
1	Western Area Power Administration	Brandy A Dunn	Negative	
1	Western Farmers Electric Coop.	Forrest Brock	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	Alberta Electric System Operator	Mark B Thompson	Abstain	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Gregory Van Pelt		
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Negative	
2	Independent Electricity System Operator	Kim Warren	Affirmative	
2	ISO New England, Inc.	Kathleen Goodman		
2	Midwest ISO, Inc.	Jason L Marshall	Negative	View
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System	Gregory Campoli		

	Operator			
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Abstain	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters		
3	American Electric Power	Raj Rana		
3	Anaheim Public Utilities Dept.	Kelly Nguyen	Abstain	
3	APS	Steven Norris	Abstain	
3	Arkansas Electric Cooperative Corporation	Philip Huff	Abstain	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	Avista Corp.	Robert Lafferty	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Blue Ridge Power Agency	Duane S Dahlquist		
3	Bonneville Power Administration	Rebecca Berdahl	Negative	
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Farmington	Linda R. Jacobson		
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Leesburg	Phil Janik	Negative	
3	Cleco Corporation	Michelle A Corley	Negative	
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	

3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Abstain	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	Entergy	Joel T Plessinger		
3	FirstEnergy Solutions	Kevin Querry	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power Corporation	Lee Schuster	Negative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	
3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Negative	View
3	Great River Energy	Sam Kokkinen	Negative	
3	Hydro One Networks, Inc.	David L Kiguel	Abstain	
3	JEA	Garry Baker	Abstain	
3	Kansas City Power & Light Co.	Charles Locke	Abstain	
3	Kissimmee Utility Authority	Gregory David Woessner	Abstain	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	Manitoba Hydro	Greg C. Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	
3	Mississippi Power	Don Horsley	Affirmative	
3	Muscatine Power & Water	John S Bos	Abstain	
3	Nebraska Public Power District	Tony Eddleman	Abstain	
3	New York Power Authority	Marilyn Brown	Affirmative	

3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Abstain	
3	PacifiCorp	John Apperson	Abstain	
3	PECO Energy an Exelon Co.	Vincent J. Catania		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters	Negative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Abstain	
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Abstain	
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Negative	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young		
3	Southern California Edison Co.	David Schiada	Negative	View
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey		

3	Tennessee Valley Authority	Ian S Grant	Negative	View
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Wisconsin Electric Power Marketing	James R. Keller	Abstain	
3	Xcel Energy, Inc.	Michael Ibold		
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	American Public Power Association	Allen Mosher	Abstain	
4	Arkansas Electric Cooperative Corporation	Ronnie Frizzell	Abstain	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Negative	
4	Consumers Energy	David Frank Ronk	Abstain	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney		
4	Fort Pierce Utilities Authority	Thomas W. Richards	Negative	
4	Georgia System Operations Corporation	Guy Andrews	Negative	View
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		

4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Tallahassee Electric	Allan Morales	Affirmative	View
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5		Edwin B Cano		
5	AEP Service Corp.	Brock Ondayko	Negative	View
5	Amerenue	Sam Dwyer	Affirmative	
5	Arizona Public Service Co.	Edward Cambridge	Abstain	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	
5	City and County of San Francisco	Daniel Mason		
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Alan Gale	Abstain	
5	Cleco Power	Stephanie Huffman		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy	James B Lewis	Affirmative	
5	Covanta Energy	Samuel Cabassa	Abstain	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	El Paso Electric Company	Alfred W Morgan		
5	Electric Power Supply Association	Jack Cashin		
5	Energy Northwest - Columbia	Doug Ramey		

	Generating Station			
5	Entergy Corporation	Stanley M Jaskot	Abstain	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	Florida Municipal Power Agency	David Schumann		
5	Great River Energy	Cynthia E Sulzer		
5	Green Country Energy	Greg Froehling	Affirmative	
5	Indeck Energy Services, Inc.	Rex A Roehl	Negative	View
5	Kansas City Power & Light Co.	Scott Heidtbrink	Abstain	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	Thomas J Trickey		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin		
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Nebraska Public Power District	Don Schmit	Abstain	
5	New Harquahala Generating Co. LLC	Nicholas Q Hayes		
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern California Power Agency	Tracy R Bibb		
5	Northern Indiana Public Service Co.	Michael K Wilkerson		
5	Occidental Chemical	Michelle DAntuono	Negative	View
5	Omaha Public Power District	Mahmood Z. Safi	Abstain	

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5	Orlando Utilities Commission	Richard Kinas		
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Abstain	
5	Platte River Power Authority	Pete Ungerman	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	Progress Energy Carolinas	Wayne Lewis	Negative	
5	Public Service Enterprise Group Incorporated	Dominick Grasso	Abstain	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Abstain	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Carolina Electric & Gas Co.	Richard Jones		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Negative	View
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.		
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Abstain	
5	Xcel Energy, Inc.	Liam Noailles		

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6	AEP Marketing	Edward P. Cox	Negative	View
6	Ameren Energy Marketing Co.	Jennifer Richardson	Affirmative	
6	Arizona Public Service Co.	Justin Thompson	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	
6	Cleco Power LLC	Robert Hirchak	Negative	
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Abstain	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Abstain	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	
6	Florida Municipal Power Agency	Richard L. Montgomery		
6	Florida Municipal Power Pool	Thomas E Washburn	Negative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Abstain	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Abstain	
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Abstain	
6	PacifiCorp	Scott L Smith	Negative	

6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Abstain	
6	Progress Energy	John T Sturgeon	Negative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	RRI Energy	Trent Carlson		
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Mike Hummel		
6	Santee Cooper	Suzanne Ritter	Negative	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	View
6	Western Area Power Administration - UGP Marketing	John Stonebarger		
6	Xcel Energy, Inc.	David F. Lemmons		
8		James A Maenner	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Affirmative	
8	INTELLIBIND	Kevin Conway		
8	JDRJC Associates	Jim D. Cyrulewski	Affirmative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	California Energy Commission	William Mitchell Chamberlain		

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9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Negative	
9	Oregon Public Utility Commission	Jerome Murray	Abstain	
9	Snohomish County PUD No. 1	William Moojen	Abstain	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Abstain	
10	Southwest Power Pool Regional Entity	Stacy Dochoda		
10	Texas Reliability Entity	Larry D Grimm	Abstain	

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Consideration of Comments on Non-binding Poll — Relay Loadability Order 733 (Project 2010-13)
Date of Non-binding Poll: January 24 – February 14, 2011

Summary Consideration: A 20-day non-binding poll was conducted for the Transmission Relay Loadability Version 2 VRF/VSLs from January 24, 2011 to February 14, 2011. The non-binding poll on the VRF/VSLs, 80.0% of those registered provided an opinion, and 65% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed.

Commenters offered their opinions in a variety of areas that can be summarized as follows:

1. Preference for additional gradations in the proposed VRF/VSLs
2. Some of the proposed VRFs and VSLs are too severe
3. Consideration of the proper Functional Entity to decide on the circuits and equipment that operate at less than or equal to 100 kV that are subject to this standard
4. Criteria for determination of the 'critical facilities' eliminates the facility's owner ability to establish criticality of its owned equipment

Approximately 50% of the commenters expressed concern about the lack of gradients in the definition of the VSLs. Many thought that having only one level (Severe) was too extreme, and many requested that multiple severity levels be defined. The drafting team explained that if a VSL is binary in nature (either the requirement is met or it isn't), FERC has directed in Order 733 that binary VSLs be treated as Severe. The drafting team stated that it believes the binary VSLs for Requirements R1 through R5 in PRC-023-2 are consistent with Order 733. Requirement R6 does have VSLs defined with gradations that are appropriate for the nature of that requirement.

Commenters expressed concern that the VSLs were too severe for the associated impact to reliability. The drafting team noted that the impact to reliability is not relevant to assigning VSLs. The drafting team clarified that Violation Risk Factors (VRFs) identify the potential reliability significance of noncompliance with each requirement while Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved.

Commenters expressed concern about which of the Functional Entities is best suited to identify which circuits and equipment should be identified as critical to the reliable operation of the grid. Many thought the standard was providing the Regional Entities with unilateral authority, but the drafting team noted that PRC-023 does not grant the Regional Entity any authority, but rather reflects language already contained in the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list entities that do not own or operate "a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity." However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES.

The drafting team also indicated that screening of the critical facilities list will be performed by the Planning Coordinator who is required to apply the criteria in Attachment B to these facilities to identify which circuits on the list are relevant to the reliability objective of PRC-023-2. The Planning Coordinator must apply the criteria in Attachment B to all facilities operated below 100 kV that are on a critical facilities list. However, the Facility owners are required to comply with PRC-023-2 only for those circuits selected by the Planning Coordinator in accordance with Requirement R6.

The drafting team indicated that the process for determining which facilities are critical to the reliable operation of the BES is well contained because it requires that the determination must (i) be based on technical studies or assessments and (ii) must be made in consultation with the

Facility owner. While the drafting team understands the need for Facility owner input, it also believes it is inappropriate to give the Facility owner de facto veto power by using the phrase "upon mutual agreement with." The Planning Coordinator will give due consideration to the Facility owner's input, and in cases where the Facility owner disagrees with the determination of the Planning Coordinator, the Facility owner is free to use the appeals process in Section 1700 of the NERC Rules of Procedure, which was developed to address this concern.

A few commenters provided more technical comments regarding the requirements of the PRC-023-2 standard, and these responses are provided in coordination with the Consideration of Comments responses with respect to the successive ballot comments.

If you feel that the drafting team overlooked your comments, 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, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Edward P. Cox Brock Ondayko Paul B. Johnson	AEP Marketing AEP Service Corp. American Electric Power	6 5 1	Negative	It is unclear why there is an absence of gradients in the VSL for many of the requirements. For example, there are many similar requirements in other standards that have VSL thresholds based on a percentage of equipment not meeting the element(s) of the requirement.
Response: Thank you for your comment. Requirements R1 through R5 are similar in structure to Requirements R1 and R2 in the approved PRC-023-1. FERC directed binary VSLs for Requirements R1 and R2 in Order 733 and the drafting team believes binary VSLs for Requirements R1 through R5 in PRC-023-2 are consistent with that Order.				
Randall McCamish Thomas E Washburn Stan T. Rzad	City of Vero Beach Florida Municipal Power Pool Keys Energy Services	1 6 1	Negative	The Regional Entity is not the correct entity to make decisions concerning what < 100 kV equipment is critical or not. It is too subject to inconsistent criteria being applied across the continent. It also is not in alignment with the regulatory construct of a stakeholder process described in Section 215 of the Federal Power Act which affords us the opportunity to learn from each other and develop better answers and solutions that appropriately balance costs, benefits and risks. Development of criteria and the application of that criteria ought to be a collaborative process continent-wide such that the criteria are applied consistently across the continent. This can be done separately, or as part of the BES definition effort currently underway. In the interim, many regions have Planning Coordinators that are not

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td></td><td>self-regulating, e.g., the Planning Coordinator is separate from the asset owners. Most of the Planning Coordinators are stakeholder organization whose "Planning Committees" would make the determination. For entities that do self-regulate, e.g., they are both the asset owner and Planning Coordinator, presumably the Regional Entity could form a stakeholder process with a Planning Committee whose members include appropriate and balanced representation from the stakeholders. These "Planning Committees" could be an alternative source for a stakeholder process to determine criteria for < 100 kV Applicability and apply that criteria while a continent-wide effort is underway to determine that criteria. These "Planning Committees" could remain in place to apply the continent-wide criteria to the regional system.</td></tr>
<tr><td colspan="5">Response: Thank you for your comment.

The drafting team notes that PRC-023 does not grant the Regional Entity any authority, rather it reflects language already contained in the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list entities that do not own or operate “a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity (emphasis added).” However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES.</td></tr>
<tr><td>Luther E. Fair</td><td>Gainesville Regional Utilities</td><td>1</td><td>Negative</td><td>The Regional Entity is not the correct entity to make decisions concerning what < 100 kV equipment is critical or not. It also is not in alignment with the regulatory construct of a stakeholder process described in Section 215 of the Federal Power Act which affords us the opportunity to learn from each other and develop better answers and solutions that appropriately balance costs, benefits and risks.</td></tr>
<tr><td colspan="5">Response: Thank you for your comment.

The drafting team notes that PRC-023 does not grant the Regional Entity any authority, rather it reflects language already contained in the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list entities that do not own or operate “a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity (emphasis added).” However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are part of the BES.</td></tr>
<tr><td>Harold Taylor, II

R Scott S. Barfield-McGinnis</td><td>Georgia Transmission Corporation

Georgia System Operations</td><td>1

3</td><td>Negative</td><td>Binary severity level for R1 through R5 appears to focus blame for 2003 Black Out solely on relay loadability and fails to note the 11 other contributing factors to the cascading black-out (bottom of page 14, "Analysis of Violation Risk Factors and Violation Severity Levels PRC-023-2 - Transmission Relay Loadability").</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
Guy Andrews	Corporation Georgia System Operations Corporation	4		
Response: Thank you for your comments. The drafting team notes that Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. The drafting team has limited consideration of the role of relay loadability in the August 14, 2003 Northeast Blackout to assigning of VRFs, which identify the potential reliability significance of noncompliance with each requirement. Requirements R1 through R5 are similar in structure to Requirements R1 and R2 in the approved PRC-023-1. FERC directed binary VSLs for Requirements R1 and R2 in Order 733, and the drafting team believes binary VSLs for Requirements R1 through R5 in PRC-023-2 are consistent with that Order.				
Gordon Pietsch	Great River Energy	1	Negative	1. R1 criteria 10.1 states that load response transformer fault protection relays should be set so that the settings do not expose the transformer to a fault current and duration that exceeds the transformer's mechanical withstand capability. If load responsive protection needs to have its pickup increased due to not meeting R1 criteria 10, this amount of load current should not be near the transformer's mechanical withstand capability. We recommend that the drafting team add a Rational Box or other supporting documentation that more clearly explains what the risks are. 2. In addition, we are requesting an expanded description in Measure 1 on what exactly is required as evidence of calculations performed.
Response: Thank you for your comments. 1. The drafting team agrees that it is possible to set fault protection relays to meet the relay loadability requirement in criterion 10 while coordinating the relay setting with the mechanical withstand capability. The explanation provided by the drafting team in response to comments on the previous posting would be an appropriate addition to the Reference Document posted with the standard. 2. The drafting team has listed, within Measure M1, the types of evidence that it feels to be most appropriate to demonstrate compliance with Requirement R1. However, the drafting team is unable to provide a definitive list of evidence that may be found compliant by the Compliance Enforcement Authority.				
Rex A Roehl	Indeck Energy Services, Inc.	5	Negative	Assigning only Severe VSL's for R1 - R5 is inappropriate. How can the PC have three levels of VSL's and an individual, perhaps with a single facility affected by this standard be in Severe violation. The SDT has avoided the hard questions of what level applies to what and assigned all to Severe. However important they think this standard is, not all violations will automatically cause cascading outages or

Voter	Entity	Segment	Vote	Comment
				instability.
Response: Thank you for your comments. The drafting team notes that Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. The drafting team has limited consideration of the role of relay loadability in the August 14, 2003 Northeast Blackout to assigning of VRFs, which identify the potential reliability significance of noncompliance with each requirement. Requirements R1 through R5 are similar in structure to Requirements R1 and R2 in the approved PRC-023-1. FERC directed binary VSLs for Requirements R1 and R2 in Order 733 and the drafting team believes binary VSLs for Requirements R1 through R5 in PRC-023-2 are consistent with that Order.				
Joe D Petaski Greg C. Parent S N Fernando Daniel Prowse	Manitoba Hydro	1 3 5 6	Negative	The VSLs for R6 are too severe. The system doesn't change that rapidly and getting the list to the entities involved before 60 days does not impact reliability given that they have 2 years to comply with changes.
Response: Thank you for your comment. The impact to reliability is not relevant to assigning VSLs. The drafting team notes that Violation Risk Factors (VRFs) identify the potential reliability significance of noncompliance with each requirement while Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. The drafting team believes that the Severe VSL is appropriate for Requirement R6.				
Terry Harbour	MidAmerican Energy Co.	1	Negative	Nearly all the VSLs are a binary in nature resulting in a zero defect standard with a "severe" result. This is an incorrect usage of the VSL concept which was to show graduated levels of risk, not deterministic zero defect results. This incorrect enforcement concept actually slows reliability progress by delaying standard implementation and hurts the concept of the new "administrative ticket process". FERC will be reluctant to allow the administrative ticket process to be used for a "severe" VSL violation even if it can be shown there was little to no BES risk.
Response: Thank you for your comment. Requirements R1 through R5 are similar in structure to Requirements R1 and R2 in the approved PRC-023-1. FERC directed binary VSLs for Requirements R1 and R2 in Order 733 and the drafting team believes binary VSLs for Requirements R1 through R5 in PRC-023-2 are consistent				

Voter	Entity	Segment	Vote	Comment
with that Order.				
Christopher Schneider	MidAmerican Energy Co.	5	Negative	Comment: 1. The Attachment B5 criteria determining critical facilities appears to be wide open and eliminates the facility owner's authority to determine what are and are not "critical" facilities on its own system based upon wording in Attachment B. The word "critical" is used throughout other NERC standards and has many potential implications. To give one entity, the Planning Coordinator, the power to assign the designation of "critical" potentially over a facility owners objection based upon any study or study criteria the Planning Coordinator decides is valid is inappropriate. Criteria B5 should be deleted. If B5 is not deleted, a minimum, the B5 wording "in consultation with" should be replaced with "upon mutual agreement with". The facility owner who best understands its facilities should have some final say in conjunction with its Planning Coordinator in determining what is and is not critical to its system and the region. 2. The drafting team change in Attachment B1 of adding the word "permanent" in front of "flowgate" did not correct the fundamental issue that a "flowgate" is not by definition a reliability issue and has no more measurable risk than the loss of any other BES transmission element. An example is the loss of a 161 kV flowgate, might have less reliability impact than the loss of a 345 or 500 kV line that is not designated as a flowgate. Therefore the criteria to define a "critical" facility through a flowgate designation is fundamentally in error. A better definition of "critical" is if the loss of a transmission element results in instability, uncontrolled separation, and cascading as defined in the Federal Power Act. 3. Vote negative on the VSLs Nearly all the VSLs are a binary in nature resulting in a zero defect standard with a "severe" result. This is an incorrect usage of the VSL concept which was to show graduated levels of risk, not deterministic zero defect results. This incorrect enforcement concept actually slows reliability progress by delaying standard implementation and hurts the concept of the new "administrative ticket process". FERC will be reluctant to allow the administrative ticket process to be used for a "severe" VSL violation even if it can be shown there was little to no BES risk.
Response: Thank you for your comments. 1. The authority for identifying circuits below 200 kV for which Facility owners must comply with PRC-023-2 is assigned to the Planning Coordinators in PRC-023-1. The drafting team believes that criterion B5 in Attachment B of PRC-023-2 is not wide-open because it requires that the determination must (i) be based on technical studies or assessments and (ii) must be made in consultation with the Facility owner. While the drafting team understands the need for Facility owner input, we also believe it is inappropriate to give the Facility Owner de facto veto power by using the phrase "upon mutual agreement with." We believe the Planning Coordinator will give due consideration to the				

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td colspan="5">Facility owner’s input, and in cases where the Facility owner disagrees with the determination of the Planning Coordinator they are free to use the appeals process in Section 1700 of the NERC Rules of Procedure that was developed to address this concern.

2. As noted in the NERC Glossary, “Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits.” This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. To the extent that Flowgates are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates.

3. Requirements R1 through R5 are similar in structure to Requirements R1 and R2 in the approved PRC-023-1. FERC directed binary VSLs for Requirements R1 and R2 in Order 733 and the drafting team believes binary VSLs for Requirements R1 through R5 in PRC-023-2 are consistent with that Order.</td></tr>
<tr><td>Jason L Marshall</td><td>Midwest ISO, Inc.</td><td>2</td><td>Negative</td><td>We disagree with a High VRF for Requirement 6. A High VRF implies there is a direct coorelation between instability, uncontrolled separation and cascading outages and a violation of the requirement. In this case, there is not such a coorelation because another standards requirement violation would have to occur such as operating above SOLs. At worst, this should have a Medium VRF.</td></tr>
<tr><td colspan="5">Response: Thank you for your comment.

The drafting team believes the VRF for Requirement R6 is appropriate and notes that the reliability objective of Requirement R6 in PRC-023-2 is the same as Requirement R3 in the FERC approved PRC-023-1: for Planning Coordinators to determine the sub-200 kV facilities for which responsible entities will be will be subject to the Requirements in the standard. The High VRF for Requirement R6 is consistent with the VRF for Requirement in PRC-023-1. FERC directed a High VRF in Order 733 noting their expectation for consistency between VRFs assigned to Requirements that address similar reliability goals. Since the facilities identified by the Planning Coordinator pursuant to Requirement R6 are required to meet Requirement R1 which is assigned a High VRF, Requirement R6 also has been assigned a High VRF since the reliability objective of Requirement R1 cannot be achieved if Planning Coordinators do not identify circuits subject to the standard.</td></tr>
<tr><td>Richard Burt</td><td>Minnkota Power Coop. Inc.</td><td>1</td><td>Negative</td><td>1. 115 kV lines should be included based on the impact they will have on the bulk system if they trip. Appendix B calls for them to be included if their risk of overload is above a threshold, regardless of their value to the bulk system. MPC's 115 kV transmission in northwest Minnesota has 3 principal 230 kV sources. With two of them outaged per the procedure in Appendix B, we may very well overload the third source. However, the risk is primarily to the load served by that 115 kV system, not the surrounding bulk system. By the procedure in Appendix B (B4a), the 115 kV sources would probably need to meet the standard, but they should not have to, due to the fact that the at-risk load is contained within the 115 kV system.
2. There are several places where the standard mandates how entities go about protecting their equipment so that it is not put at risk. R1 Criteria 10.1 and the</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
				related measurement M1 is an example. This goes beyond the reach of NERC. It is the entity's' prerogative how to protect its equipment. 3. R1 Criteria 5 needs further explanation. 4. R1 Criteria 6 seems too vague. Is it only to be applied to generation that has one radial tie to the bulk system? What if the generation is injected in the middle of a long line with no local load, so there are in essence two outlets? 5. In R1 Criteria 12, it appears that the 87% margin should be based on MVA, not current. Basing it on current appears to compromise the margin.
Response: 1. The Purpose stated in PRC-023 includes ensuring that protective relay settings do not interfere with system operators' ability to take remedial action to protect system reliability. While the August 14, 2003 Northeast Blackout was the primary motivation behind development of the standard, the reliability objective of the standard is not limited to preventing wide-area outages. Smaller scale outages may impact system reliability and the criteria in Attachment B were developed specifically to address the reliability objective of this standard. The drafting team believes the criteria in Attachment B will identify circuits that are relevant to the reliability objective of PRC-023-2; however, as directed in ¶97 of Order 733, NERC has developed an appeals process so that Facility owners may challenge the determination of the Planning Coordinators. The appeals process will be contained in Section 1700 of the NERC Rules of Procedure. 2. The standard does not mandate how entities are to protect their equipment. The standard is limited to establishing relay loadability requirements to prevent circuits from tripping unnecessarily before an operator has time to take corrective action to mitigate the potential for instability, uncontrolled separation, or cascading outages. In the case of criterion 10.1, the standard does not require the use of load responsive transformer fault protection relays, it only requires coordination with the mechanical withstand capability of the transformer. How this coordination is achieved is up to the Facility owner. 3. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that Requirement R1, criterion 5 is unchanged from the approved PRC-023-1. Additional explanation is provided in the Reference Document posted with standard PRC-023-1. 4. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that Requirement R1, criterion 6 is unchanged from the approved PRC-023-1. Additional explanation is provided in the Reference Document posted with standard PRC-023-1. 5. Equipment thermal ratings are based on current rather than MVA. Applying the margin to the calculated current is correct as stated.				
Saurabh Saksena	National Grid	1	Affirmative	1. List of Critical Facilities: Since a critical facilities list would be prepared for other reasons (e.g. CIP-002), National Grid is assuming that the list of critical facilities will be reviewed for applicability to PRC-023 and that a subset of the list may need to be defined for this application. 2. There appears to be inconsistency in the wording pertaining to the sentence - "critical facilities list defined by the Regional Entity and selected by the Planning Coordinator". In 4.2.1.3 the aforementioned sentence is produced in its entirety.

Voter	Entity	Segment	Vote	Comment
				However, in attachment B, under Circuits to Evaluate, bullet point 2, the sentence is missing "...and selected by the Planning Coordinator". This piece is also missing in 4.2.2.2. 3. Attachment B, B4 a.: National Grid requests the drafting team to explain the rationale behind deleting "Category C3" from B4. National Grid believes that by providing reference to Category C3, the standard focuses on the scope and provides for consistency in the engineering judgment. However, by deleting Category C3, the scope becomes undefined as to the level of combinations that need to be assessed and will concern the engineer that his engineering judgment can be called into question. 4. Summary consideration on pg. 1 regarding supervisory elements associated with current based, communication assisted schemes having to meet PRC-023-2 and inclusion of such elements in Attachment A, 1.6: This is taken to mean line differential schemes. If the supervisory elements for a line diff must be set high enough to comply with PRC-023-2 that will make the entire scheme extremely insensitive to faults. For example R1.1 would require the supervising elements be set > 1.5 x the 4 hr. loading meaning the scheme will be unable to detect an internal fault unless it exceeds 1.5 x the 4 hr. loading. That negates one of the chief advantages of using a line differential scheme in the first place, specifically it's sensitivity. If the communications for a relay scheme is lost the scheme is essentially "broken" and to require it to still function correctly per PRC-023-2 even when broken is unreasonable. There is no requirement that distance schemes conform to PRC-023-2 if they are broken, for example if they lose their restraint potential they will trip on load too. 5. Switch on to fault scheme included in Attachment A, 1.3 - An exception needs to be added for those schemes that are smart enough to detect a live line condition and which are disabled when closing or reclosing into an already energized line. Such schemes will not respond to current flow into and through a live line. Requiring that such a SOTF scheme that can recognize a live line be set to carry through current regardless, negates the advantage of the scheme in the first place, specifically its sensitivity. 6. Regarding R1, Criterion 10 - What if the transformer at the end of the line has its own overcurrent protection that either trips a local high side breaker or circuit switcher or TT's the other end of the source line and this transformer overcurrent protection is set below the mechanical damage curve. Must the line protection back at the source to the line still be set below the transformer's mechanical damage curve? If your answer is yes, what if the line protection is step distance with a flat timer, like a zone 2 timer. Coordinating a zone 2 looking into the transformer and having a flat zone 2 timer against and inverse

Voter	Entity	Segment	Vote	Comment
				transformer mechanical damage curve is awkward at best and maybe not even feasible. 7. Regarding R1, Criterion 5 - "Weak source system" is a relative term. Is the reader free to define "weak" as the reader chooses? If not then it needs to be defined in the standard.
Response: Thank you for your comments. 1. Yes, additional screening will be applied. The Planning Coordinator is required to apply the criteria in Attachment B to these facilities to identify which circuits on the list are relevant to the reliability objective of PRC-023-2. 2. These differences are intentional. Where the phrase is not included it is referring to the circuits that must be evaluated by the Planning Coordinator. The Planning Coordinator must apply the criteria in Attachment B to all facilities operated below 100 kV that are on a critical facilities list. However, the Facility owners are required to comply with PRC-023-2 only for those circuits selected by the Planning Coordinator in accordance with Requirement R6. 3. The reference to category C3 contingencies resulted in confusion with some entities because the test required in criterion B4 is not the same as category C3 since criterion B4 does not include manual system adjustments between contingencies. 4. Items included in Section 1.6 of Attachment A are included to address the concerns noted by FERC in Order 733. Settings for the protection schemes of concern are often very sensitive – well below load current – and dependent on the integrity of the communication channel to make a trip/no trip decision where other telecommunication system technologies require the operation of other protection system elements (usually distance elements) which are already subject to the requirements of this standard. Therefore, they will trip immediately due to load current upon the loss of communications, and are dependent on the fault detectors to inhibit trip which must therefore be secure regardless of how infrequently loss of communications may occur. 5. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that Attachment A, Section 1.3 is unchanged from the approved PRC-023-1. However, the drafting team will include your recommendations in the issues database for future consideration in the next general revision of the standard. 6. No, in the previous posting the drafting team separated the relay loadability aspect and the transformer fault protection aspect of criterion 10. The transformer fault protection relays and transmission line relays both must meet the relay loadability requirements listed in the two bullets in criterion 10. Only the transformer fault protection relays, if used, must be coordinated with the transformer mechanical withstand capability. 7. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that Requirement R1, criterion 5 is unchanged from the approved PRC-023-1. Entities may apply criterion 5 to any line, although when the source becomes sufficiently strong this criterion will become more restrictive than others.				
Michelle DAntuono	Occidental Chemical	5	Negative	Need justification as to why the VSLs are listed as Severe.

Voter	Entity	Segment	Vote	Comment
Response: Thank you for your comment. Requirements R1 through R5 are similar in structure to Requirements R1 and R2 in the approved PRC-023-1. FERC directed binary VSLs for Requirements R1 and R2 in Order 733 and the drafting team believes binary VSLs for Requirements R1 through R5 in PRC-023-2 are consistent with that Order. In the case of binary VSLs, the VSLs are set to Severe by definition.				
David Schiada	Southern California Edison Co.	3	Negative	We do not feel that the concerns raised in comments on the last round of balloting have been adequately addressed. Among the concerns still remaining are the use of "critical facilities" in several of the requirements and the respective roles that Regional Entities and Planning Coordinators will play in identifying critical facilities.
Response: Thank you for your comments. The Regional Entity may develop a list of critical facilities by means outside this standard. The reference to a list of critical facilities in PRC-023-2 is in the same context as the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list an entity that does not own or operate "a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity (emphasis added)." To provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has replaced the reference to a "list of critical facilities" with a reference to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES". The role of the Planning Coordinator is defined in Requirement R6. The Planning Coordinator will be required to apply the criteria in Attachment B in accordance with Requirement R6 of PRC-023-2 to identify any circuits on the list for which the Facility owner must comply with PRC-023-2.				
Allan Morales	Tallahassee Electric	4	Affirmative	Heading "Implementation Plan for PRCRPC-023-2:" Transmission Relay Loadability" has PRC crossed out with RPC in place. Should remain PRC.
Response: Thank you for your comment. The heading in the Implementation Plan has been corrected.				
Ian S Grant	Tennessee Valley Authority	3	Negative	the severity level is too great for what is essentially documentation errors
David Thompson		5		The severity level is too great for what are essentially documentation errors. For example, for Requirement 7, if the PC takes 31 days to send their critical list to neighboring RCs and PCs, it should not be a Moderate VSL but something less severe.
Marjorie S. Parsons		6		
Response: Thank you for your comment. The drafting team notes that Violation Risk Factors (VRFs) identify the potential reliability significance of noncompliance with each requirement while Violation Severity Levels (VSLs) define the degree to which compliance with a requirement was not achieved. For the reporting related Requirements, R3 through R5, the drafting team believes that the Medium VRF for Requirement R3 and the Lower VRFs for Requirements R4				

Voter	Entity	Segment	Vote	Comment
and R5 accurately reflect the potential reliability significance of non-compliance. Please note that the Medium VRF for Requirement R3 is consistent with the FERC approved PRC-023-1. The VSLs for these requirements are based on the VSLs directed in FERC Order 733 for the FERC approved PRC-023-1. The VSLs are binary because an entity has either provided documentation or it has not, and binary VSLs are Severe by definition. Please note that Requirement R7 was removed from the standard prior to the most recent posting to address industry concerns with double jeopardy.				
Gregg R Griffin	City of Green Cove Springs	3	Negative	From the last posting to this posting, for COM-002-3 R2, the phrase "the accuracy of the message has been confirmed" was added to the second step of three part communication. "Accuracy" is not the correct term here. "Understanding" is a better term. It would seem that "accuracy" is a term to be used in R3, the third part of the 3-part communication so that the issuer of the directive ensures the accuracy of the recipients understanding. FMPA suggests changing COM-002-3 R2 to read: Each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider, Load-Serving Entity, Distribution Provider, and Purchasing-Selling Entity that is the recipient of a Reliability Directive issued per Requirement R1, shall repeat, restate, rephrase or recapitulate the Reliability Directive with enough details to clearly communicate the recipient's understanding of the Reliability Directive.. The term "accuracy" can be interpreted as requiring the recipient to second-guess the Reliability Directive of the RC to enure the accuracy of the RC's directive in the first place. Under tight time constraints of Emergencies, this is not practical. We are sure that was not the intent of the drafting team. For IRO-001-2, FMPA does not see a need for R1. Doesn't the ERO already have that authority to establish RC's through the registration process, and to certify system operators through the PER standards? IRO-014-2 R5, "impacted" was replaced with "other". Wouldn't it be better to at least limit the notification to within the same interconnection? Or is R5 truly to identify all NERC registered RC's? More minor comments / suggestions for improvement: IRO-002 R2 can be improved by replacing "prevent identified events" with "prevent anticipated events". "Anticipated" aligns better with contingency analysis than "identified" IRO-005-4 R1 and R2 can be improved by replacing "expected" with "anticipated". Contingencies are not necessarily "expected"; however, we do "anticipate" them.
Response: Thank you for your comments. It appears that your comments pertain to Project 2006-06 – Reliability Coordination. The formal comment period for Project 2006-06 is open through March 7, 2011. Please submit your comments through the NERC website.				

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Successive Ballot and Non-binding Poll Open
Project 2010-13 – Relay Loadability Order 733 Modifications
January 24-February 13, 2011

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2010-13: Revisions to Relay Loadability for Order 733

PRC-023-2 — Transmission Relay Loadability has been posted for a 20-day successive ballot of the proposed standard and its associated implementation plan through **8 p.m. on February 13, 2011**. A non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) will be conducted during the same time.

Registered Ballot Body members who joined the ballot pool to vote on the standard have already been automatically entered in a separate pool to participate in the non-binding poll for the VRFs and VSLs. For ballot pool members, the non-binding poll appears in the list of current ballots, and is labeled accordingly.

Instructions

Members of the ballot pools associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

Background

This standard was revised to address a set of directives in Order 733 and must be submitted to FERC by March 18, 2011. To meet this delivery date, the Standards Committee authorized use of the expedited standard development process. Under the expedited standard development process, the Standards Committee may alter certain steps in the standard development process to meet a regulatory deadline. In this case, the Standards Committee authorized the drafting team to conduct successive ballots without parallel comment periods. To allow stakeholders time to review the changes made between ballots, the Standards Committee authorized an extended ballot window of 20 calendar days, rather than 10 calendar days.

Next Steps

Voting results will be posted and announced after the ballot windows close.

Project Background

When FERC issued Order 733, approving PRC-023-1 —Transmission Relay Loadability, it directed several changes to that standard and also directed development of one or more new standards within specified time periods. NERC filed for clarification and rehearing, asking for clarity and an extension of time to address the directives; however, without a response to the requests for clarification and rehearing, NERC must proceed as though these requests will be denied.

The SAR for Project 2010-13 subdivides the standard-development-related directives into three phases. Phase I

addresses the specific directives from Order 733 that identified required modifications to various elements within PRC-023-1. Phase II addresses directives associated with development of a new standard to address generator relay loadability. Phase III addresses directives associated with writing requirements to address protective relay operations due to power swings.

More information on this project may be found on the project page:

http://www.nerc.com/filez/standards/SAR_Project%202010-13_Order%20733%20Relay%20Modifiations.html

Standards 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 Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

North American Electric Reliability Corporation
116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com

Ballot Results	
Ballot Name:	2010-13 Relay Loadability Order Successive Ballot_in
Ballot Period:	1/24/2011 - 2/14/2011
Ballot Type:	Initial
Total # Votes:	272
Total Ballot Pool:	324
Quorum:	**83.95 % The Quorum has been reached**
Weighted Segment Vote:	65.71 %
Ballot Results:	**The standard will proceed to recirculation ballot.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	97	1	52	0.703	22	0.297	13	10
2 - Segment 2.	11	0.8	5	0.5	3	0.3	1	2
3 - Segment 3.	72	1	33	0.647	18	0.353	8	13
4 - Segment 4.	21	1	9	0.643	5	0.357	5	2
5 - Segment 5.	67	1	27	0.711	11	0.289	12	17
6 - Segment 6.	38	1	17	0.63	10	0.37	6	5
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.4	2	0.2	2	0.2	2	1
9 - Segment 9.	5	0.2	1	0.1	1	0.1	2	1
10 - Segment 10.	6	0.5	4	0.4	1	0.1	0	1
Totals	**324**	**6.9**	**150**	**4.534**	**73**	**2.366**	**49**	**52**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	View
1	APS	Barbara McMinn		
1	Arizona Public Service Co.	Robert D Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott Kinney	Affirmative	

1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Beaches Energy Services	Joseph S. Stonecipher	Negative	
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	CenterPoint Energy	Paul Rocha	Negative	View
1	Central Maine Power Company	Kevin L Howes	Abstain	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Vero Beach	Randall McCamish	Negative	View
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	View
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Commonwealth Edison Co.	Gregory Campbell		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	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	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Negative	View
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	View
1	Great River Energy	Gordon Pietsch	Negative	View
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Affirmative	
1	Idaho Power Company	Ronald D. Schellberg		
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stan T. Rzad	Negative	View
1	Lake Worth Utilities	Walt Gill	Negative	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	View
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Richard Burt	Negative	View
1	National Grid	Saurabh Saksena	Affirmative	View
1	Nebraska Public Power District	Richard L. Koch	Affirmative	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura		
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Omaha Public Power District	Douglas G Peterchuck	Affirmative	
1	Oncor Electric Delivery	Michael T. Quinn	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas		
1	PacifiCorp	Colt Norrish	Affirmative	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Negative	View
1	PowerSouth Energy Cooperative	Larry D. Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Abstain	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Catherine Koch	Negative	View
1	Rochester Gas and Electric Corp.	John C. Allen	Abstain	

1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Abstain	
1	Santee Cooper	Terry L. Blackwell	Negative	
1	SCE&G	Henry Delk, Jr.	Abstain	
1	Seattle City Light	Pawel Krupa	Abstain	
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon	Abstain	
1	Southern California Edison Co.	Dana Cabbell	Negative	View
1	Southern Company Services, Inc.	Horace Stephen Williamson		
1	Southern Illinois Power Coop.	William G. Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Larry Akens	Affirmative	View
1	Texas Municipal Power Agency	Frank J. Owens	Abstain	
1	Transmission Agency of Northern California	James W. Beck	Abstain	
1	Tri-State G & T Association, Inc.	Keith V Carman	Negative	View
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Negative	View
1	Western Farmers Electric Coop.	Forrest Brock	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Gregory Van Pelt		
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Negative	View
2	Independent Electricity System Operator	Kim Warren	Affirmative	View
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Jason L Marshall	Negative	View
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Abstain	
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters		
3	American Electric Power	Raj Rana		
3	Anaheim Public Utilities Dept.	Kelly Nguyen	Abstain	
3	APS	Steven Norris	Affirmative	
3	Arkansas Electric Cooperative Corporation	Philip Huff	Abstain	
3	Atlantic City Electric Company	James V. Petrella	Negative	
3	Avista Corp.	Robert Lafferty	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blue Ridge Power Agency	Duane S Dahlquist		
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Farmington	Linda R. Jacobson		
3	City of Green Cove Springs	Gregg R Griffin	Negative	View
3	City of Leesburg	Phil Janik	Negative	
3	Cleco Corporation	Michelle A Corley	Negative	View
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Abstain	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	
3	Detroit Edison Company	Kent Kujala	Negative	
3	Dominion Resources Services	Michael F Gildea	Affirmative	
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	View
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power Corporation	Lee Schuster	Negative	
3	Georgia Power Company	Anthony L Wilson	Affirmative	

3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Great River Energy	Sam Kokkinen	Negative	
3	Hydro One Networks, Inc.	David L Kiguel	Affirmative	
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory David Woessner	Negative	View
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Abstain	
3	Manitoba Hydro	Greg C. Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	View
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	View
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	PacifiCorp	John Apperson	Negative	
3	PECO Energy an Exelon Co.	Vincent J. Catania		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Potomac Electric Power Co.	Robert Reuter		
3	Progress Energy Carolinas	Sam Waters	Negative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Abstain	
3	Public Utility District No. 2 of Grant County	Greg Lange		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Abstain	
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Negative	
3	Seattle City Light	Dana Wheelock	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young		
3	Southern California Edison Co.	David Schiada	Negative	View
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey		
3	Tennessee Valley Authority	Ian S Grant	Affirmative	View
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Wisconsin Electric Power Marketing	James R. Keller	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	American Public Power Association	Allen Mosher	Affirmative	
4	Arkansas Electric Cooperative Corporation	Ronnie Frizzell	Abstain	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Negative	
4	Consumers Energy	David Frank Ronk	Negative	View
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Negative	View
4	Fort Pierce Utilities Authority	Thomas W. Richards	Negative	View
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Negative	View
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean		
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen	Abstain	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Abstain	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Tallahassee Electric	Allan Morales	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5		Edwin B Cano		
5	AEP Service Corp.	Brock Ondayko	Affirmative	View

5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Alan Gale	Abstain	
5	Cleco Power	Stephanie Huffman		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Abstain	
5	Consumers Energy	James B Lewis	Negative	View
5	Covanta Energy	Samuel Cabassa	Abstain	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	El Paso Electric Company	Alfred W Morgan		
5	Electric Power Supply Association	Jack Cashin		
5	Energy Northwest - Columbia Generating Station	Doug Ramey		
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	Florida Municipal Power Agency	David Schumann		
5	Great River Energy	Cynthia E Sulzer		
5	Green Country Energy	Greg Froehling	Affirmative	
5	Indeck Energy Services, Inc.	Rex A Roehl	Negative	View
5	Kansas City Power & Light Co.	Scott Heidtbrink	Negative	View
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	Thomas J Trickey		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin		
5	Luminant Generation Company LLC	Mike Laney	Affirmative	
5	Manitoba Hydro	S N Fernando	Negative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New Harquahala Generating Co. LLC	Nicholas Q Hayes		
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern California Power Agency	Tracy R Bibb		
5	Northern Indiana Public Service Co.	Michael K Wilkerson		
5	Occidental Chemical	Michelle DAntuono	Negative	View
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Negative	View
5	Platte River Power Authority	Pete Ungerman	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Abstain	
5	Progress Energy Carolinas	Wayne Lewis	Negative	
5	Public Service Enterprise Group Incorporated	Dominick Grasso	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Affirmative	
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Abstain	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Abstain	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Abstain	
5	South Carolina Electric & Gas Co.	Richard Jones		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tampa Electric Co.	RJames Rocha		
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	View
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.		
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Abstain	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	

6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	View
6	Arizona Public Service Co.	Justin Thompson	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	View
6	Cleco Power LLC	Robert Hirchak	Negative	View
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Abstain	
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Abstain	
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View
6	Florida Municipal Power Agency	Richard L. Montgomery		
6	Florida Municipal Power Pool	Thomas E Washburn	Negative	View
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	View
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	View
6	Lakeland Electric	Paul Shipps	Affirmative	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Abstain	
6	PacifiCorp	Scott L Smith	Negative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Abstain	
6	Progress Energy	John T Sturgeon	Negative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	RRI Energy	Trent Carlson		
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Mike Hummel		
6	Santee Cooper	Suzanne Ritter	Negative	
6	Seattle City Light	Dennis Sismaet	Abstain	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	View
6	Western Area Power Administration - UGP Marketing	John Stonebarger		
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	
8		James A Maenner	Abstain	
8		Roger C Zaklukiewicz	Affirmative	
8		Edward C Stein	Affirmative	
8	INTELLIBIND	Kevin Conway		
8	JDRJC Associates	Jim D. Cyrulewski	Negative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	California Energy Commission	William Mitchell Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Negative	
9	Oregon Public Utility Commission	Jerome Murray	Abstain	
9	Snohomish County PUD No. 1	William Moojen	Abstain	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Affirmative	
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Carter B Edge	Affirmative	
10	Southwest Power Pool Regional Entity	Stacy Dochoda		
10	Texas Reliability Entity	Larry D Grimm	Negative	View

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Standards Announcement

Successive Ballot Results

Project 2010-13 - Relay Loadability for Order 733

Now available at: https://standards.nerc.net/Ballots.aspx

A successive initial ballot of PRC-023-2 — Transmission Relay Loadability ended on February 14, 2011. Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results.

Ballot for Standard:

- Quorum: 83.95%
- Approval: 65.71%

Violation Risk Factor (VRF) and Violation Severity Level (VSL) Non-binding Poll Results:

- The poll achieved a quorum with 80% of those who registered to participate provided an opinion; 65% of those who provided an opinion indicated support for the VRFs and VSLs that were proposed.

Project Background:

When FERC issued Order 733, approving PRC-023-1 — Transmission Relay Loadability, it directed several changes to that standard and also directed development of one or more new standards within specified time periods. NERC filed a request for clarification and rehearing, and requested additional time to address the directives; however, pending FERC's response to the requests for clarification and additional time, NERC must progress as though these requests will be denied.

The SAR for Project 2010-13 subdivides the standard-development-related directives into three phases. Phase I addresses the specific directives from Order 733 that identified required modifications to various elements within PRC-023-1. Phase II addresses directives associated with development of a new standard to address generator relay loadability. Phase III addresses directives associated with writing requirements to address protective relay operations due to power swings. More details may be found on the project page: http://www.nerc.com/filez/standards/SAR_Project%202010-13_Order%20733%20Relay%20Modifiations.html

Next Steps

The drafting team will consider all comments (those submitted with a comment form and those submitted with a ballot) and will determine whether to make additional changes to the standard. The team will post its response to comments and if the standard has only minor changes, will post the standard and conduct a 10-day recirculation ballot.

Ballot Criteria

Approval requires both (1) a quorum, which is established by at least 75% of the members of the ballot pool submitting either an affirmative vote, a negative vote, or an abstention, and (2) a two-thirds majority of the weighted segment votes cast must be affirmative; the number of votes cast is the sum of affirmative and negative votes, excluding abstentions and non-responses.

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

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Consideration of Comments on Successive Ballot — Relay Loadability Order (Project 2010-13)

Date of Successive Ballot: January 24 – February 14, 2011

Summary Consideration: A 20-day successive ballot was conducted for the Transmission Relay Loadability Version 2 standard PRC-023-2 from January 24, 2011 to February 14, 2011. The successive ballot achieved a quorum of 83.95% and a weighted segment approval of 65.71%. In addition to pointing out inconsistencies in the text of the PRC-023-2 standard, which the drafting team acknowledged and revised, commenters raised concerns in a few technical areas and the drafting team evaluated and responded to these concerns providing clarification and updates to the standard's text as noted below Some comments went beyond the scope of the project. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that the structure of the standard is unchanged from the approved PRC-023-1 and its requirements are consistent with the "Zone 3" and "Beyond Zone 3" reviews completed by industry following the August 14, 2003 Northeast Blackout. Suggested changes to the standard that require further modifications will be evaluated and added to the issues database for future consideration when making the next set of revisions to PRC-023.

Commenters expressed concern that (in the applicability section of the standard) the Regional Entity is being given additional authority to identify what equipment operating at or less than 100 kV is critical to the reliable operation of the grid. The drafting team noted that PRC-023 does not grant the Regional Entity any authority, rather it reflects language already contained in the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list entities that do not own or operate "a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity." However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES."

Commenters were also concerned about the selection of critical facilities according to the criteria in Attachment B and the apparent elimination of the facility owner's authority to determine which facilities are or are not included on the critical facilities list. The drafting team pointed out that an entity may confirm with their Regional Entity whether it has any circuits operated below 100 kV on a list of critical facilities. However, when circuits operated below 100 kV are identified on such a list, the Planning Coordinator is required to apply the criteria in Attachment B to the list of critical facilities to determine which circuits on the list are relevant to the reliability objectives of PRC-023-2 and for which the Facility owner must comply with PRC-023-2. This determination must (i) be based on technical studies or assessments and (ii) must be made in consultation with the Facility owner. While the drafting team understands the need for Facility owner input, it is also inappropriate to give the Facility Owner de facto veto power by using the phrase "upon mutual agreement with." The drafting team believes the Planning Coordinator will give due consideration to the Facility owner's input, and in cases where the Facility owner disagrees with the determination of the Planning Coordinator, an appeals process in Section 1700 of the NERC Rules of Procedure has been developed to address this concern.

Commenters raised concerns about the use of flowgates or permanent flowgates as a criterion to designate a facility as critical from a reliability perspective. The drafting team noted that the NERC Glossary states that "Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits." This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. To the extent that Flowgates are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates.

Commenters raised concerns regarding the removal of the reference to category C3 contingencies in Attachment B, criterion B4 of PRC-023-2, which includes the consideration of double contingency events without manual system adjustments between contingencies. The drafting team indicated that the purpose of the B4 criterion is to determine whether relays must be set to meet loadability requirements such that the circuits will

not be tripped prematurely, resulting in widening of the initiating outage if manual adjustments were not completed before the second contingency. The test identified in criterion B4 is consistent with, and developed specifically to address, the reliability concern driving the need for this standard. The drafting team notes that if manual adjustments were allowed between contingencies in criterion B4, this criterion would not identify any circuits subject to this standard except in cases where TPL-003 is violated. The test appropriately identifies circuits that may be loaded to levels that challenge relay settings when multiple contingencies occur. The drafting team also clarified that the reference to category C3 contingencies was removed since it resulted in confusion with some entities because the test required in criterion B4 is not the same as category C3, since criterion B4 does not include manual system adjustments between contingencies.

Some commenters indicated that there is confusion in the wording regarding Attachment A, Section 1.6 with respect to the listing of those protective functions that are within the scope of PRC-023-2 and requested clarification. The drafting team acknowledged this confusion and inserted parenthetical statements to clarify that the phrase “phase overcurrent supervisory elements” refers to phase fault detectors and “current-based communication-assisted schemes” refers to pilot wire, phase comparison, and line current differential schemes.

If you feel that the drafting team overlooked your comments, 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, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Voter	Entity	Segment	Vote	Comment
Kirit S. Shah	Ameren Services	1	Negative	(1) We do not agree with the implied establishment of ratings outside of the requirements of FAC-008 in Requirement R1, criterion 1, which implies the establishment of a 4 hour rating. Rather than specifically identify the duration, the term ‘highest seasonal long-term emergency’ rating should be used. (2) Attachment B Criterion B1 still includes the consideration of flowgates. We believe that this criterion should be removed from Attachment B. (3) Attachment B Criterion B4 includes the consideration of double contingency events without manual system adjustments between contingencies. While the specific mention of Category C3 contingencies is removed, which would permit limiting consideration of multiple contingency events to Category C1 bus fault, C2 breaker failure, and C5 common structure outages where no operator intervention would be possible, such contingency selection would be up to the Planning Coordinator, not the individual Transmission Owner. As written, the Facility owner would only have input as to the threshold level against which the post-contingency loading would be compared, rather than the selection of the multiple contingencies to be simulated. Any ‘N-1-1’ contingencies should be considered as congestion issues and should not be considered as part of the criteria in Attachment B for this

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

Voter	Entity	Segment	Vote	Comment
				reliability standard.

Response: Thank you for your comments.

1. The drafting team would understand this concern if the standard required that entities establish 4-hour ratings; however, the drafting team notes that this criterion intentionally refers to "the available defined loading duration nearest 4 hours" to make it clear that an entity is not required to develop a 4-hour rating. An entity may use an existing rating, for any time duration, so long as when multiple ratings are available an entity uses their existing rating that is based on a time duration nearest to 4 hours. This phrase has remained unchanged from the "Zone 3" and "Beyond Zone 3" reviews completed following the August 14, 2003 Northeast Blackout and is part of the approved standard PRC-023-1. The drafting team is not aware of any assertion that this criterion establishes a de facto requirement for entities to develop ratings based on 4-hour duration.
2. As noted in the NERC Glossary, "Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits." This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. To the extent that Flowgates are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates.
3. The test identified in criterion B4 is consistent with, and developed specifically to address, the reliability concern driving the need for this standard. System disturbances in which relay loadability was a contributing factor, such as occurred on August 14, 2003, involve multiple contingencies without sufficient time for operator action. The drafting team notes that if manual adjustments were allowed between contingencies in criterion B4, this criterion would not identify any circuits subject to this standard except in cases where TPL-003 is violated. The test appropriately identifies circuits that may be loaded to levels that challenge relay settings when multiple contingencies occur. When such circuits are identified the Facility owner is required to meet relay loadability requirements to prevent the circuit from tripping unnecessarily before an operator has time to take corrective action. The drafting team respectfully points out that the Facility owner is not required to take any action to prevent overloads from occurring under such circumstances; the Facility owner is required only to provide relay loadability per the requirements in PRC-023 to mitigate the potential for such N-2 contingencies from leading to instability, uncontrolled separation, or cascading outages. The drafting team believes that assigning selection of contingencies to the Planning Coordinator, and requiring Planning Coordinator consultation with the Facility owners regarding evaluation of post-contingency loading, is consistent with the NERC Functional Model.

Voter	Entity	Segment	Vote	Comment
Paul B. Johnson	American Electric Power	1	Affirmative	The wording of Attachment A, section 1.6 should be made consistent to avoid any confusion. AEP suggests that it be reworded to read: "Supervisory elements used as fault detectors associated with pilot wire or current differential protection systems where the system is capable of tripping for loss of communications".

Voter	Entity	Segment	Vote	Comment
Response: Thank you for your comment. The drafting team apologizes for confusion regarding Attachment A, Section 1.6 during the previous posting. The drafting team had intended to provide additional clarification. The drafting team has inserted parenthetical statements to clarify that the phrase "phase overcurrent supervisory elements" refers to phase fault detectors and "current-based communication-assisted schemes" refers to pilot wire, phase comparison, and line current differential schemes. We believe this modification is in-line with your recommended modification.				
Andrew Z Pusztai	American Transmission Company, LLC	1	Affirmative	None
Response: Thank you for your support.				
Donald S. Watkins	Bonneville Power Administration	1	Negative	1. BPA believes that there is a major discontinuity in the logical flow of the standard. As described in Section 4.2, the standard applies to certain transmission lines and transformers. In Requirement R1, there are thirteen criteria to select from "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". Of these thirteen criteria, only two apply to transformers--number ten and eleven. The way that these two are buried in between the other criteria that apply to line terminals and the way that they are written creates a question as to whether they apply to all transformers or only to transformers that are part of a transformer-terminated line. Additionally, since they are part of the group of thirteen criteria, of which only one must be selected, it appears that criteria ten and eleven can be ignored if another criterion is selected for a transformer-terminated line. BPA forsees this issue causing enough confusion among auditors and transmission owners that we cannot vote in favor of the standard until it is remedied. It would clear up the confusion if Criterion 10 was separated into two parts: one part that deals only with transmission line relays for transformer-terminated lines, and a second part that deals with load-responsive transformer relays. The second part--that deals with load-responsive transformer relays--should be moved along with Criterion 11 into a new requirement. This way, all of the criteria in Requirement 1 will apply only to line relays, with only one of the criteria needed to ensure that the line relays will not limit transmission system loadability. The new requirement (suggest using R2 and bumping the other requirements up a number) would deal specifically with load responsive transformer relays. Because this requirement would not be

Voter	Entity	Segment	Vote	Comment
				intermingled among the 13 optional criteria of Requirement 1, it would be clear that all load responsive transformer relays--not just those for transformer-terminated lines--were required to comply. 2. The drafting team has cleared up a major issue with Criterion 10.1 of Requirement 1 by clarifying that load responsive transformer relays must not expose a transformer to fault levels and durations that exceed the transformers mechanical withstand capability. This makes the requirement achievable, while the earlier version, which required that the relays not expose a transformer to fault levels and durations that exceeded its capability, was not. However, the mechanical withstand capability is not a well defined value, and the drafting team's use of a footnote to clarify this requirement is not sufficient. BPA agrees with the use of IEEE C57.109-1993 as the best way to define mechanical withstand capability, but if this is to be used as the measure of this requirement, it should be written into the requirement and not merely mentioned as a footnote. In addition, Clause 4.4, Figure 4 of IEEE C57.109-1993, as mentioned in the footnote, applies only to Category IV transformers. A close look at the standard reveals that the mechanical withstand capability curves for the other categories are not the same, and the requirements for these other categories must be identified as well.

Response: Thank you for your comments

1. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that the structure of Requirement R1 is unchanged from the approved PRC-023-1 and is consistent with the “Zone 3” and “Beyond Zone 3” reviews completed by industry following the August 14, 2003 Northeast Blackout. The drafting team provided additional clarity specific to criterion 10 by splitting the fault protection aspect directed in the order (now part 10.1) from the relay loadability aspects. The drafting team believes that combining portions of criteria 10 and 11 at this time would add confusion by intermingling fault protective relays and overload relays. However, the drafting team will include your recommendations in the issues database for future consideration in the next general revision of the standard.

2. The drafting team believes that because the reference does not establish a requirement, rather it defines the phrase mechanical withstand capability, it is most appropriately included as a footnote rather than within Requirement R1, criterion 10. The drafting team also believes that a general citing of IEEE C57.109 within the requirements would be problematic in that we are only referencing a portion of the standard. The drafting team notes that the mechanical withstand is well-defined within the standard and that a specific reference to Clause 4.4, Figure from IEEE C57.109-1993 referenced in PRC-023-2 is sufficient. Category IV transformers are defined as transformers over 10,000 kVA (10 MVA) single-phase or 30,000 kVA (30 MVA) three-phase. Since this standard applies to BES facilities, the drafting team believes that the vast majority (if not all) of the applicable transformers will be Category IV transformers; if any Category III transformers fall within the applicability of this standard, the associated mechanical characteristic is virtually identical.

Voter	Entity	Segment	Vote	Comment
Paul Rocha	CenterPoint Energy	1	Negative	For the Effective Dates for circuits identified by the Planning Coordinator pursuant to Requirement R6, CenterPoint Energy is concerned that, as PRC-023-2 is currently written, these identified circuits will be required to meet the loadability requirements even though planning-sponsored system improvements completed prior to the effective dates would alleviate inclusion of the circuit on the list. CenterPoint Energy would support Draft 2 if the wording “unless system changes, that alleviate inclusion of the circuit on the list, are completed before the applicable effective date is added to the end of 5.1.2.1 and 5.2.2.1. For example, 5.1.2.1 would be “The 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 system changes, that alleviate inclusion of the circuit on the list, are completed before the applicable effective date.”
Response: The drafting team had intended that if a circuit identified in the near-term planning horizon no longer meets any of the criteria in Attachment B due to system improvements, the Facility would not be required to comply with the requirements of PRC-023 for that circuit. The drafting team has added a phrase to the end of 5.1.2.1 and 5.2.2.1 in the Effective Dates section to address your concern, although the drafting team has omitted the recommended reference to “system changes that alleviate inclusion of the circuit on the list.” This phrase was omitted to make the modification applicable to any reason for which the Planning Coordinator removes the circuit from the list before the applicable effective date.				
Randall McCamish	City of Vero Beach	1	Negative	The Regional Entity is not the correct entity to make decisions concerning what < 100 kV equipment is critical or not. It is too subject to inconsistent criteria being applied across the continent. It also is not in alignment with the regulatory construct of a stakeholder process described in Section 215 of the Federal Power Act which affords us the opportunity to learn from each other and develop better answers and solutions that appropriately balance costs, benefits and risks. Development of criteria and the application of that criteria ought to be a collaborative process continent-wide such that the criteria are applied consistently across the continent. This can be done separately, or as part of the BES definition effort currently underway. In the interim, many regions have Planning Coordinators that are not self-regulating, e.g., the Planning Coordinator is separate from the asset owners. Most of the Planning Coordinators are stakeholder organization whose "Planning Committees" would make the determination. For entities that do self-regulate, e.g., they are both the asset owner and Planning Coordinator, presumably the Regional Entity could form a stakeholder process with a Planning Committee whose members include appropriate and balanced representation from the stakeholders. These "Planning Committees" could be an alternative source for a stakeholder process to determine criteria for < 100 kV Applicability and apply that criteria while a

Voter	Entity	Segment	Vote	Comment
				continent-wide effort is underway to determine that criteria. These "Planning Committees" could remain in place to apply the continent-wide criteria to the regional system.
Response: Thank you for your comment. The drafting team notes that PRC-023 does not grant the Regional Entity any authority, rather it reflects language already contained in the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list entities that do not own or operate "a transmission element below 100 kV associated with <u>a facility that is included on a critical facilities list that is defined by the Regional Entity</u> (emphasis added)." However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES."				
Danny McDaniel	Cleco Power LLC	1	Negative	Section 4.2 establishes the conditions to ultimately include the entire electric power infrastructure under the umbrella of protecting the "bulk electric system" which was originally defined as 200kV and above. Cleco is concerned this ever expanding regulatory umbrella is not justified.
Response: Thank you for your comment. The drafting team believes that Section 4.2 will identify only those circuits that if they trip due to relay loadability, may contribute to undesirable system performance similar to what occurred during the August 14, 2003 blackout. The criteria developed in Attachment B were developed to achieve this purpose. To the extent the commenter is concerned with the reference to facilities operated below 100 kV, the drafting team points out that consistent with the FERC position in Order 733-A we expect that references to circuits operated below 100 kV will have narrow applicability. The drafting team also notes that to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this the reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES."				
Robert Martinko	FirstEnergy Energy Delivery	1	Affirmative	We applaud the drafting team for their diligent and expeditious work on responding to the FERC directives of Order 733. We support the standard but ask that the team clarify the effective dates. Compliance Application Notice CAN-0013 which was recently posted for industry comment correctly adds clarification to the actual effective date for (1) Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System; (2) Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System; and (3) Switch-on-to-fault schemes on all applicable facilities. Since this CAN specifies the date of October 1, 2013 in the U.S., we ask that the following

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td></td><td>sections of PRC-023-2 be revised to include this date: "5.1.1.1.3 For switch-on-to-fault schemes as described in PRC-023-2 - Attachment A, Section 1.3, the later of the first day of the first calendar quarter after applicable regulatory approval of PRC-023-2 or the first day of the first calendar quarter 39 months following applicable regulatory (October 1, 2013 in the U.S.) approval of PRC-023-1; or in those jurisdictions where no regulatory approval is required, the later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011." and "5.1.2.1 The later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator (October 1, 2013 in the U.S.) 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.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.

The drafting team acknowledges the complexity involved in the effective dates for this standard. The drafting team has reformatted the Effective Dates section of the standard into a tabular format consistent with CAN-0013 and has inserted the US effective date (October 1, 2013) where appropriate.</td></tr>
<tr><td>Luther E. Fair</td><td>Gainesville Regional Utilities</td><td>1</td><td>Negative</td><td>The Regional Entity is not the correct entity to make decisions concerning what < 100 kV equipment is critical or not. It also is not in alignment with the regulatory construct of a stakeholder process described in Section 215 of the Federal Power Act which affords us the opportunity to learn from each other and develop better answers and solutions that appropriately balance costs, benefits and risks.</td></tr>
<tr><td colspan="5">Response: Thank you for your comment.

The drafting team notes that PRC-023 does not grant the Regional Entity any authority, rather it reflects language already contained in the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list entities that do not own or operate "a transmission element below 100 kV associated with <u>a facility that is included on a critical facilities list that is defined by the Regional Entity</u> (emphasis added)." However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES."</td></tr>
<tr><td>Harold Taylor, II</td><td>Georgia Transmission Corporation</td><td>1</td><td>Affirmative</td><td>The hyperlink on page 13 of the draft 3: January 21, 2011 does not work. Recommendation for future reference: Do not insert hyperlinks in documents. Instead, place recommended search words to be inserted into the "SEARCH</td></tr>
</table>

Voter	Entity	Segment	Vote	Comment
				NERC.com" window. That is much less likely to become broken in the future.
Response: Thank you for your comment. The drafting team has updated the hyperlink and in consideration of your comment has updated the description of the reference document to facilitate a search if necessary.				
Gordon Pietsch	Great River Energy	1	Negative	1. R1 Criteria 10.1 states that load responsive transformer fault protection relays should be set so that the settings do not expose the transformer to a fault current and duration that exceeds the transformer's mechanical withstand capability. If load responsive protection needs to have its pickup increased due to not meeting R1 Criteria 10, this amount of load current should not be near the transformer's mechanical withstand capability. We recommend that the drafting team add a Rationale Box or other supporting documentation that more clearly explains what the risks are. 2. In addition we are requesting an expanded description in Measure 1 on what exactly is required as evidence of calculations performed.
Response: Thank you for your comments. The drafting team agrees that it is possible to set fault protection relays to meet the relay loadability requirement in criterion 10 while coordinating the relay setting with the mechanical withstand capability. The explanation provided by the drafting team in response to comments on the previous posting would be an appropriate addition to the Reference Document posted with the standard.				
Michael Gammon	Kansas City Power & Light Co.	1	Negative	1. The criteria with Attachment B is not consistent with the TPL planning standards and is likely to identify transmission facilities that do not pose a reliability threat to the operation of the interconnection. The criteria in Attachment B should focus on identifying transmission facilities that play a reliability role in maintaining equipment loadings within SOL and IROL facility ratings and not include other considerations such as flowgates which are a mechanism for energy market management. 2. In addition, the implementation time frames specified are not clear whether the implementation time frame of 24 months is an extension from the 18 month time frame for the RC to identify circuits using the criteria in Attachment B or if the 24 months is concurrent with the 18 months. Also, it is uncertain whether the 24 months will be sufficient without knowing the impact of the RC analysis.

Voter	Entity	Segment	Vote	Comment
Response: Thank you for your comments. 1. The criteria identified in Attachment B are consistent with, and developed specifically to address, the reliability concern driving the need for this standard. The drafting team continues to believe that Flowgates addressing reliability concerns for loading of circuits is an appropriate inclusion in these criteria. As noted in the NERC Glossary, “Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits.” This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. To the extent that Flowgates are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates. 2. The drafting team believes the commenter is referring to the time provided to a Facility owner to comply with PRC-023 after the Planning Coordinator identifies a circuit is subject to PRC-023-2 per application of Attachment B. The drafting team notes that in the previous posting of the standard this timeframe was extended from 24 months to 39 months. Specific to the commenter’s question, the standard identifies the 39 months are measured from “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.” The 39 months in neither concurrent with nor an extension of the 18 months provided to the Planning Coordinator.				
Stan T. Rzad	Keys Energy Services	1	Negative	The Regional Entity is not the correct entity to make decisions concerning what < 100 kV equipment is critical or not. It is too subject to inconsistent criteria being applied across the continent. It also is not in alignment with the regulatory construct of a stakeholder process described in Section 215 of the Federal Power Act which affords us the opportunity to learn from each other and develop better answers and solutions that appropriately balance costs, benefits and risks. Development of criteria and the application of that criteria ought to be a collaborative process continent-wide such that the criteria are applied consistently across the continent. This can be done separately, or as part of the BES definition effort currently underway. In the interim, many regions have Planning Coordinators that are not self-regulating, e.g., the Planning Coordinator is separate from the asset owners. Most of the Planning Coordinators are stakeholder organization whose "Planning Committees" would make the determination. For entities that do self-regulate, e.g., they are both the asset owner and Planning Coordinator, presumably the Regional Entity could form a stakeholder process with a Planning Committee whose members include appropriate and balanced representation from the stakeholders. These "Planning Committees" could be an alternative source for a stakeholder process to determine criteria for < 100 kV Applicability and apply that criteria while a continent-wide effort is underway to determine that criteria. These "Planning Committees" could remain in place to apply the continent-wide criteria to the regional system.

Voter	Entity	Segment	Vote	Comment
Response: Thank you for your comment. The drafting team notes that PRC-023 does not grant the Regional Entity any authority, rather it reflects language already contained in the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list entities that do not own or operate "a transmission element below 100 kV associated with <u>a facility that is included on a critical facilities list that is defined by the Regional Entity</u> (emphasis added)." However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES."				
Joe D Petaski	Manitoba Hydro	1	Negative	Please see comments previously submitted by Manitoba Hydro regarding 1. the effective date and 2. the items included in Section 1.6 of Attachment A.
Response: Thank you for your comments. 1. The drafting team has considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1. Extending the timeframe included consideration of the number of circuits that may be identified by the Planning Coordinator. 2. Items included in Section 1.6 of Attachment A are included to address the concerns noted by FERC in Order 733. Settings for the protection schemes of concern are often very sensitive – well below load current – and dependent on the integrity of the communication channel to make a trip/no trip decision where other telecommunication system technologies require the operation of other protection system elements (usually distance elements) which are already subject to the requirements of this standard. Therefore, they will trip immediately due to load current upon the loss of communications, and are dependent on the fault detectors to inhibit trip which must therefore be secure regardless of how infrequently loss of communications may occur.				
Terry Harbour	MidAmerican Energy Co.	1	Negative	1. The Attachment B5 criteria determining critical facilities appears to be wide open and eliminates the facility owner's authority to determine what are and are not "critical" facilities on its own system based upon wording in Attachment B. The word "critical" is used throughout other NERC standards and has many potential implications. To give one entity, the Planning Coordinator, the power to assign the designation of "critical" potentially over a facility owners objection based upon any study or study criteria the Planning Coordinator decides is valid is inappropriate. Criteria B5 should be deleted. If B5 is not deleted, a minimum, the B5 wording "in consultation with" should be replaced with "upon mutual agreement with". The facility owner who best understands its facilities should have some final say in conjunction with its Planning Coordinator in determining what is and is not critical to its system and the region. 2. The drafting team change in Attachment B1 of adding the word "permanent" in

Voter	Entity	Segment	Vote	Comment
				front of "flowgate" did not correct the fundamental issue that a "flowgate" is not by definition a reliability issue and has no more measurable risk than the loss of any other BES transmission element. An example is the loss of a 161 kV flowgate, might have less reliability impact than the loss of a 345 or 500 kV line that is not designated as a flowgate. Therefore the criteria to define a "critical" facility through a flowgate designation is fundamentally in error. A better definition of "critical" is if the loss of a transmission element results in instability, uncontrolled separation, and cascading as defined in the Federal Power Act.
Response: Thank you for your comments. 1. The authority for identifying circuits below 200 kV for which Facility owners must comply with PRC-023-2 is assigned to the Planning Coordinators in PRC-023-1. The drafting team believes that criterion B5 in Attachment B of PRC-023-2 is not wide-open because it requires that the determination must (i) be based on technical studies or assessments and (ii) must be made in consultation with the Facility owner. While the drafting team understands the need for Facility owner input, we also believe it is inappropriate to give the Facility Owner de facto veto power by using the phrase "upon mutual agreement with." We believe the Planning Coordinator will give due consideration to the Facility owner's input, and in cases where the Facility owner disagrees with the determination of the Planning Coordinator they are free to use the appeals process in Section 1700 of the NERC Rules of Procedure that was developed to address this concern. 2. As noted in the NERC Glossary, "Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits." This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. To the extent that Flowgates are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates.				
Richard Burt	Minnkota Power Coop. Inc.	1	Negative	1. 115 kV lines should be included based on the impact they will have on the bulk system if they trip. Appendix B calls for them to be included if their risk of overload is above a threshold, regardless of their value to the bulk system. MPC's 115 kV transmission in northwest Minnesota has 3 principal 230 kV sources. With two of them outaged per the procedure in Appendix B, we may very well overload the third source. However, the risk is primarily to the load served by that 115 kV system, not the surrounding bulk system. By the procedure in Appendix B (B4a), the 115 kV sources would probably need to meet the standard, but they should not have to, due to the fact that the at-risk load is contained within the 115 kV system. 2. There are several places where the standard mandates how entities go about protecting their equipment so that it is not put at risk. R1 Criteria 10.1 and the related measurement M1 is an example. This goes beyond the reach of NERC. It

Voter	Entity	Segment	Vote	Comment
				is the entity's' prerogative how to protect its equipment. 3. R1 Criteria 5 needs further explanation. 4. R1 Criteria 6 seems too vague. Is it only to be applied to generation that has one radial tie to the bulk system? What if the generation is injected in the middle of a long line with no local load, so there are in essence two outlets? 5. In R1 Criteria 12, it appears that the 87% margin should be based on MVA, not current. Basing it on current appears to compromise the margin.
Response: Thank you for your comments. 1. The Purpose stated in PRC-023 includes ensuring that protective relay settings do not interfere with system operators' ability to take remedial action to protect system reliability. While the August 14, 2003 Northeast Blackout was the primary motivation behind development of the standard, the reliability objective of the standard is not limited to preventing wide-area outages. Smaller scale outages may impact system reliability and the criteria in Attachment B were developed specifically to address the reliability objective of this standard. The drafting team believes the criteria in Attachment B will identify circuits that are relevant to the reliability objective of PRC-023-2; however, as directed in ¶97 of Order 733, NERC has developed an appeals process so that Facility owners may challenge the determination of the Planning Coordinators. The appeals process will be contained in Section 1700 of the NERC Rules of Procedure. 2. The standard does not mandate how entities are to protect their equipment. The standard is limited to establishing relay loadability requirements to prevent circuits from tripping unnecessarily before an operator has time to take corrective action to mitigate the potential for instability, uncontrolled separation, or cascading outages. In the case of criterion 10.1, the standard does not require the use of load responsive transformer fault protection relays, it only requires coordination with the mechanical withstand capability of the transformer. How this coordination is achieved is up to the Facility owner. 3. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that Requirement R1, criterion 5 is unchanged from the approved PRC-023-1. Additional explanation is provided in the Reference Document posted with standard PRC-023-1. 4. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that Requirement R1, criterion 6 is unchanged from the approved PRC-023-1. Additional explanation is provided in the Reference Document posted with standard PRC-023-1. 5. Equipment thermal ratings are based on current rather than MVA. Applying the margin to the calculated current is correct as stated.				
Saurabh Saksena	National Grid	1	Affirmative	1. List of Critical Facilities: Since a critical facilities list would be prepared for other reasons (e.g. CIP-002), National Grid is assuming that the list of critical facilities will be reviewed for applicability to PRC-023 and that a subset of the list may need to be defined for this application. 2. There appears to be inconsistency in the wording pertaining to the sentence - "critical facilities list defined by the Regional Entity and selected by the Planning Coordinator". In 4.2.1.3 the aforementioned sentence is produced in its entirety.

Voter	Entity	Segment	Vote	Comment
				However, in attachment B, under Circuits to Evaluate, bullet point 2, the sentence is missing "...and selected by the Planning Coordinator". This piece is also missing in 4.2.2.2. 3. Attachment B, B4 a.: National Grid requests the drafting team to explain the rationale behind deleting "Category C3" from B4. National Grid believes that by providing reference to Category C3, the standard focuses on the scope and provides for consistency in the engineering judgment. However, by deleting Category C3, the scope becomes undefined as to the level of combinations that need to be assessed and will concern the engineer that his engineering judgment can be called into question. 4. Summary consideration on pg. 1 regarding supervisory elements associated with current based, communication assisted schemes having to meet PRC-023-2 and inclusion of such elements in Attachment A, 1.6: This is taken to mean line differential schemes. If the supervisory elements for a line diff must be set high enough to comply with PRC-023-2 that will make the entire scheme extremely insensitive to faults. For example R1.1 would require the supervising elements be set > 1.5 x the 4 hr. loading meaning the scheme will be unable to detect an internal fault unless it exceeds 1.5 x the 4 hr. loading. That negates one of the chief advantages of using a line differential scheme in the first place, specifically it's sensitivity. If the communications for a relay scheme is lost the scheme is essentially "broken" and to require it to still function correctly per PRC-023-2 even when broken is unreasonable. There is no requirement that distance schemes conform to PRC-023-2 if they are broken, for example if they lose their restraint potential they will trip on load too. 5. Switch on to fault scheme included in Attachment A, 1.3 - An exception needs to be added for those schemes that are smart enough to detect a live line condition and which are disabled when closing or reclosing into an already energized line. Such schemes will not respond to current flow into and through a live line. Requiring that such a SOTF scheme that can recognize a live line be set to carry through current regardless, negates the advantage of the scheme in the first place, specifically its sensitivity. 6. Regarding R1, Criterion 10 - What if the transformer at the end of the line has its own overcurrent protection that either trips a local high side breaker or circuit switcher or TT's the other end of the source line and this transformer overcurrent protection is set below the mechanical damage curve. Must the line protection back at the source to the line still be set below the transformer's mechanical damage curve? If your answer is yes, what if the line protection is step distance with a flat timer, like a zone 2 timer. Coordinating a zone 2

Voter	Entity	Segment	Vote	Comment
				looking into the transformer and having a flat zone 2 timer against and inverse transformer mechanical damage curve is awkward at best and maybe not even feasible. 7. Regarding R1, Criterion 5 - "Weak source system" is a relative term. Is the reader free to define "weak" as the reader chooses? If not then it needs to be defined in the standard.

Response: Thank you for your comments.

1. Yes, additional screening will be applied. The Planning Coordinator is required to apply the criteria in Attachment B to these facilities to identify which circuits on the list are relevant to the reliability objective of PRC-023-2.
2. These differences are intentional. Where the phrase is not included it is referring to the circuits that must be evaluated by the Planning Coordinator. The Planning Coordinator must apply the criteria in Attachment B to all facilities operated below 100 kV that are on a critical facilities list. However, the Facility owners are required to comply with PRC-023-2 only for those circuits selected by the Planning Coordinator in accordance with Requirement R6.
3. The reference to category C3 contingencies resulted in confusion with some entities because the test required in criterion B4 is not the same as category C3 since criterion B4 does not include manual system adjustments between contingencies.
4. Items included in Section 1.6 of Attachment A are included to address the concerns noted by FERC in Order 733. Settings for the protection schemes of concern are often very sensitive – well below load current – and dependent on the integrity of the communication channel to make a trip/no trip decision where other telecommunication system technologies require the operation of other protection system elements (usually distance elements) which are already subject to the requirements of this standard. Therefore, they will trip immediately due to load current upon the loss of communications, and are dependent on the fault detectors to inhibit trip which must therefore be secure regardless of how infrequently loss of communications may occur.
5. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that Attachment A, Section 1.3 is unchanged from the approved PRC-023-1. However, the drafting team will include your recommendations in the issues database for future consideration in the next general revision of the standard.
6. No, in the previous posting the drafting team separated the relay loadability aspect and the transformer fault protection aspect of criterion 10. The transformer fault protection relays and transmission line relays both must meet the relay loadability requirements listed in the two bullets in criterion 10. Only the transformer fault protection relays, if used, must be coordinated with the transformer mechanical withstand capability.
7. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that Requirement R1, criterion 5 is unchanged from the approved PRC-023-1. Entities may apply criterion 5 to any line, although when the source becomes sufficiently strong this criterion will become more restrictive than others.

Voter	Entity	Segment	Vote	Comment
David Thorne	Potomac Electric Power Co.	1	Negative	Attachment A of the standard provides a listing of those protective functions that would be in scope. Presently Section 1.6 of Attachment A is worded as "Supervisory elements associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communication." In our comments on the previous ballot we stated: " The intent of this section was to specifically address phase overcurrent supervising elements (i.e. phase fault detectors) associated with pilot wire, phase comparison, and line current differential schemes where the scheme is capable of tripping for loss of communications. However, we believe that the term "current-based communication-assisted schemes" is too generic and may be confusing without mention of the specific schemes to which this requirement applies....Therefore, to clarify the requirement we suggest replacing the current wording with either "Phase overcurrent supervisory elements (i.e. phase fault detectors) associated with pilot wire, phase comparison, and line current differential schemes, where the scheme is capable of tripping for loss of communications" or "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 Standard Drafting Team (SDT) responded to our comment by stating "Attachment A applies to the listed protective functions that respond to load so it's unnecessary to use the word "phase". Section 1.6 has otherwise been modified essentially as you suggest in response to your comment." There was another similar comment from AEP with the same SDT response. The SDT did not modify Section 1.6 using either of our suggestions, since the wording in the current version remains exactly the same as in the previous version. This may have been an oversight by the SDT. Without specific identification of what schemes are in scope, you are leaving up to an auditor to determine what schemes are "current-based" and what "supervising elements" are you talking about.
Response: Thank you for your comment. The drafting team apologizes for confusion regarding Attachment A, Section 1.6 during the previous posting. The drafting team had intended to provide additional clarification. The drafting team has adopted your second proposal and has inserted parenthetical statements to clarify that the phrase "phase overcurrent supervisory elements" refers to phase fault detectors and "current-based communication-assisted schemes" refers to pilot wire, phase comparison, and line current differential schemes.				
Catherine Koch	Puget Sound Energy, Inc.	1	Negative	1. Puget Sound Energy believes this standard is structured in a way that will create confusion relative to required actions and timelines. For example; Section 4.2.1 Circuits Subject to Requirements R1-R5 This section refers to T-lines and transformers selected by the Planning Coordinator without any clear criteria to

Voter	Entity	Segment	Vote	Comment
				use for the selection which is impossible to comply to. 2. T-lines and Transformers below 100 kV are also applicable if they are included on a critical facilities list defined by the Regional Entity and selected by the Planning Coordinator. We have not seen this specific list and do not have any criteria for our own selection process, which makes this impossible to comply with. 3. Section 5. Effective Dates This section is confusing with 5 different effective dates which roll forward when any changes to the standard are made. These dates also refer to requirements which depend upon lists and selection criteria that have not been provided by the region. 4. Section PRC-023 Attachment B, Part B4.a, Circuit Identification Criteria "Simulate double contingency combinations selected by engineering judgment...." The words Engineering Judgment should not appear in any NERC standard. The committee chose to replace a reference to TPL 003 Category C3 which was at least something specific. It is impossible to meet compliance with something as vague as Engineering Judgment.

Response: Thank you for your comments.

1. The criteria for selection by the Planning Coordinator in Applicability Sections 4.2.1.2 and 4.2.1.5 are the same as Sections 4.2.1.3 and 4.2.1.6. These two sections also should have included the phrase "in accordance with Requirement R6" and this clarification has been added. Thank you for identifying this discrepancy.
2. An entity may confirm with their Regional Entity whether they have any circuits operated below 100 kV on a list of critical facilities. When circuits operated below 100 kV are identified on such a list, the Planning Coordinator will be required to apply the criteria in Attachment B in accordance with Requirement R6 of PRC-023-2 to identify any circuits on the list for which the Facility owner must comply with PRC-023-2. To provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has replaced the reference to a "list of critical facilities" with a reference to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES".
3. The drafting team acknowledges the complexity involved in the effective dates for this standard. The drafting team has reformatted the Effective Dates section of the standard into a tabular format to improve clarity.
4. The drafting team notes that similar to the Transmission Planning (TPL) standards, it is not reasonable to require simulation of every combination of contingencies nor is it possible to provide a bright-line to clearly define which contingencies must be simulated for every possible system topology. Some level of judgment is necessary to determine the double contingency combinations that must be simulated to meet the reliability objectives of the standard.

Voter	Entity	Segment	Vote	Comment
Dana Cabbell	Southern California Edison Co.	1	Negative	We do not feel that the concerns raised in comments on the last round of balloting have been adequately addressed. Among the concerns still remaining are the use of "critical facilities" in several of the requirements and the respective roles that Regional Entities and Planning Coordinators will play in identifying critical facilities.
Response: Thank you for your comments. The Regional Entity may develop a list of critical facilities by means outside this standard. The reference to a list of critical facilities in PRC-023-2 is in the same context as the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list an entity that does not own or operate "a transmission element below 100 kV associated with <u>a facility that is included on a critical facilities list that is defined by the Regional Entity</u> (emphasis added)." To provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has replaced the reference to a "list of critical facilities" with a reference to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES". The role of the Planning Coordinator is defined in Requirement R6. The Planning Coordinator will be required to apply the criteria in Attachment B in accordance with Requirement R6 of PRC-023-2 to identify any circuits on the list for which the Facility owner must comply with PRC-023-2.				
Larry Akens	Tennessee Valley Authority	1	Affirmative	Permanent flowgate" is too ambiguous. Most entities in the eastern interconnect use flowgates in many different processes such as EMS systems and state estimator, transfer capability calculations, congestion management processes, and market calculations. All of these processes have flowgates that could be considered "permanent". If this standard is pointing to the IDC Book of Flowgate (BOF) Permanent flowgates, then this should be so stated. However, since the IDC BOFs is not the most up to date list of flowgates, we suggest that a better line criticality identification to reliability is if a TLR has been called on the flowgate in the last two year. We recommend that instead of "permanent flowgate", the B1 portion of Attachment B1 should say " in the IDC Book of Flowgates and a TLR 3 or greater has been called on the flowgate in the last two years
Response: Thank you for your comments. The drafting team appreciates the suggestion to further refine the Flowgates of interest in the context of criterion B1. However, the drafting team believes that the Flowgates of interest must be determined based on the reliability basis for adding the Flowgate rather than historical transfers. Even if a TLR has not been called on a Flowgate for an extended period of time, during a system disturbance an overload on a monitored Facility comprising the Flowgate could lead to cascading outages if relay loadability requirements are not met. The drafting team believes it is best to continue to refer to circuits that are monitored Facilities of Flowgates that are included to address reliability concerns for loading of those circuits.				

Voter	Entity	Segment	Vote	Comment
Keith V Carman	Tri-State G & T Association, Inc.	1	Negative	1. The response to our concern about Requirement R1, Criterion 10 acknowledges that 150% of the highest rating of many transformers is 250% of the transformer's base rating. Since the transformer thermal damage curve begins at 200% of the base rating, this requirement can force entities to set relays that don't fully protect their transformers. Is Requirement R1, Criterion 13 intended to be used for those situations? We think it would be more appropriate to address the concern in Criterion 10 with language to indicate that if the loading requirement violates thermal protection, then the protection requirement rules and the relays should be set (with some reasonable margin) to allow as much loading as possible while ensuring no thermal damage. 2. With regard to requirements R4 and R5, we acknowledge the modifications of measures M4 and M5 that allows lists of incremental changes to be submitted. We believe M4 and M5 should be clarified that in the event of no changes, a submittal is not required or a submittal of "no changes" is acceptable. Periodic duplicate submittals are unnecessary and unique submittals would more easily identify the loadability issues that the operators need to consider. The FERC Order did not require annual submittals. 3. With regard to Attachment B criterion B4, we agree that it is a technically sound approach but we believe that existing TPL simulations and assessments should be utilized first to narrow the scope of the analyses. Afterwards, the new simulation that is described in criterion B4 can be implemented. An example would be if an element's loading exceeded 100% of its Facility Rating using the normal TPL assessment, then the assessment with no manual intervention would be applied and subsequent steps of criterion B4 would be followed. 4. With regard to Attachment B criterion B5, we acknowledge the modification that the Facility owner should be consulted. However, we believe that criterion B5 should be removed entirely. We believe that if criteria outside of those in B4 will be used, they should only be used if mutually agreed upon, which the new B6 expresses. We believe consultation alone does not prevent the criterion from being applied discriminatorily or differently even within the same interconnection.
Response: Thank you for your comments. 1. Relays applied for transformer fault protection are subject to Requirement 1, criterion 10. As with any relays applied for fault protection, it may not be possible to provide thermal protection. Requirement R1, criterion 11 explicitly addresses relays applied for transformer overload (thermal) protection. 2. Measures M4 and M5 have been updated to indicate that "The updated list may 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".				

Voter	Entity	Segment	Vote	Comment
3. The Planning Coordinator is free to apply the criteria in Attachment B in conjunction with analyses performed to demonstrate compliance with the Transmission Planning (TPL) standards to facilitate efficiency. One option would be for the Planning Coordinator to apply the tests as described in this comment. The drafting team believes it is best to allow this flexibility without prescriptive language that would lock a Planning Coordinator into any one approach. 4. The drafting team believes that criterion B5 in Attachment B of PRC-023-2 is appropriate because it requires that the determination must (i) be based on technical studies or assessments and (ii) must be made in consultation with the Facility owner. While the drafting team understands the need for Facility owner input, we also believe it is inappropriate to give the Facility Owner de facto veto power by using the phrase "upon mutual agreement with." We believe the Planning Coordinator will give due consideration to the Facility owner's input, and in cases where the Facility owner disagrees with the determination of the Planning Coordinator they are free to use the appeals process in Section 1700 of the NERC Rules of Procedure that was developed to address this concern. The situation covered by criterion B6 differs from criterion B5 in that mutual agreement is required in place of supporting technical studies or assessments.				
Brandy A Dunn	Western Area Power Administration	1	Negative	1. Section B Requirement R1 Criteria 10.1 This should be removed from the standard. As described in IEEE C57.109-1993, the mechanical damage portion of the curve applies to frequent faults over the life of the transformer. It may be necessary, in some cases and for some conditions, to set protective elements between the mechanical and thermal portion of the damage curve. In these cases, additional steps such as disabling or limiting automatic reclosing on neighboring circuits and/or utilizing Operational guidelines can be used to mitigate possible impacts. NERC should not direct this coordination issue but instead should leave it up to the Protection Engineer to provide a solution that fits the situation at hand. 2. Section B Requirement R1 Criteria 11 The second bullet refers to footnote 4 which refers to IEEE standard C57.115. IEEE standard C57.115 has been withdrawn for some time. The active standard is IEEE C57.91. The NERC standard needs to refer to active IEEE standards. If IEEE C57.91 does not support the statement of the second bullet under R1 11 then the NERC standard should be corrected.
Response: Thank you for your comments. 1. The drafting team disagrees with the commenter's assessment. The mechanical withstand characteristic in IEEE C57.109 is specifically characterized as applying for "faults which occur infrequently ..." The IEEE Guide considers that thermal exposure (to frequent faults) is a phenomena for which the transformer will recover when the thermal condition is relieved, while mechanical exposure (to infrequent faults) will possibly cause immediate and irrecoverable damage when the transformer's capability is exceeded. While it is true that each entity should apply their engineering judgment as well as mitigating practices to the application of protective relays, NERC is responsible to establish standards to prescribe minimum practices which the entities must meet. The drafting team believes that the use of the mechanical withstand characteristic as proposed in Requirement R1, criterion 10, is an appropriate method of addressing this concern.				

Voter	Entity	Segment	Vote	Comment
2. The drafting team appreciates identification of this issue. The reference has been changed to indicated that IEEE 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 that Annex A cautions that bubble formation may occur above 140 degrees C.				
Chuck B Manning	Electric Reliability Council of Texas, Inc.	2	Negative	Please reference December 2010 IRC comments.
Response: Thank you for your comment. The drafting team has reviewed the previous comments and believes we have adequately addressed them within the standard or explained why modifications to the standard are not warranted.				
Kim Warren	Independent Electricity System Operator	2	Affirmative	We thank the Drafting Team for responding to our comments on the previous posting. We make the following further suggestions. 1. The Applicability section now includes Section 4.2.2 - Circuits Subject to Requirement R6. These applicability statements are repeated in Attachment B with one change to the second bullet where "Transmission lines" has been replaced by "Lines". We believe this repetition is unnecessary and has led to inconsistency observed. In our view a simple reference to Section 4.2.2 would be sufficient. 2. The DT has introduced the phrase "one-to-five-year planning horizon" in Criterion B4. We suggest using the defined term "Near-Term Transmission Planning Horizon" that was developed as part of the recently balloted Project 2010-10: FAC Order 729.
Response: Thank you for your comments. 1. In the most recent posting the drafting team has eliminated much redundancy between the Applicability section, Requirement R6, and Attachment B. The drafting team acknowledges that repeating the applicability statements in Attachment B is redundant, but believes this limited amount of redundancy is beneficial in allowing a reader to obtain a complete understanding of the criteria in Attachment B without the need to refer back to the Applicability section. The drafting team has addressed the discrepancy identified by the commenter and appreciates identification of this issue. 2. The drafting team appreciates this suggestion, but is reluctant to refer to a defined term until it is included in the NERC Glossary. However, the drafting team will include your recommendation in the issues database for future consideration in the next general revision of the standard. If the term is approved at that time, we believe that making the recommended change would be appropriate.				

Voter	Entity	Segment	Vote	Comment
Kathleen Goodman	ISO New England, Inc.	2	Negative	Two issues still remain with this draft: 1. R1.2 still makes no sense and the SDT response did not seem to address our comment. 2. R4 this is a problem which wasn't in the last version that we commented on. Now, even if nothing changes, we are required to rerun everything. This seems a significant use of resources with no Reliability benefit.
Response: Thank you for your comments. 1. Requirement 1 was developed to prevent circuits from tripping unnecessarily before an operator has time to take corrective action. Recognizing that most entities do not utilize ratings for durations less than 4 hours, the initial criteria developed in response to the August 14, 2003 blackout was based on 150 percent of the Facility Rating nearest 4 hours. Criterion 2 was added to acknowledge that some entities do utilize a 15-minute rating, and that relay loadability in these cases may be based on this rating. This criterion provides an alternate method of meeting Requirement R1 when criterion 1 would result in an unrealistic relay loadability requirement (e.g. if a circuit had a 4-hour rating of 500 MVA and a 15-minute rating of 600 MVA, relay loadability may be based on 1.15 x 600 = 690 MVA instead of 1.5- x 500 = 750 MVA. In some cases this may be the difference between the Facility owner being able to reset the relays versus requiring a capital project to replace the relays. The drafting team notes that this criterion is unchanged from the “Zone 3” and “Beyond Zone 3” reviews completed following the August 14, 2003 Northeast Blackout and is part of the approved standard PRC-023-1. 2. The drafting team is confused by the comment since Requirement R4 does not require any analysis to be performed. The updated list referred to in this requirement is simply a list of circuits for which entities choose to use Requirement R1, criterion 2 to demonstrate relay loadability. The lists are developed by the Facility Owners and provided to the Planning Coordinator, Transmission Operator, and Reliability Coordinator. If the comment is directed toward criterion B4 in Attachment B, the drafting team notes that the footnote explicitly clarifies that when no material changes occur, past analyses may be used to support the assessment. This removes the burden of repeating past studies to avoid unnecessary deployment of resources.				
Jason L Marshall	Midwest ISO, Inc.	2	Negative	We appreciate the drafting team’s continuing efforts to refine the draft standard but believe there are still significant issues. 1. We continue to believe that flowgates should not be included in the criteria at all because they do not usually represent significant reliability issues that might cause instability, uncontrolled separation or cascading but in fact are primarily used to manage congestion and to sell transmission service. In response to our comments from the previous ballot, the drafting team indicated congestion and system reliability are not mutually exclusive. While we agree on this point, we disagree on some of their further points. They indicate that the transmission system is operated within the physical constraints of the transmission system to prevent instability, uncontrolled separation or cascading. This implies that all

Voter	Entity	Segment	Vote	Comment
				flowgates are associated with IROLs. This is in fact not the case and most flowgates are not associated with IROLs. Furthermore, the markets are often constrained to respect physical limitations such as equipment limits but many times these are not associated with instability, uncontrolled separation and cascading. The drafting team further indicates that the IDC is used to preserve system reliability. This is simply not the case. It is used to manage congestion in an equitable manner. The FERC in Order 693 specifically prohibited the use of the IDC to manage IROL constraints because it was not fast enough to prevent instability, uncontrolled separation and cascading outages. This was also cited in the August 2003 Blackout Report. Furthermore, this is reflected in IRO-006-4.1 R1.1. Criteria B2 will identify those circuits whose failure could lead to instability, uncontrolled separation and cascading outages obviating the need to include flowgates. 2. We do not support criterion B4. It exceeds what is required in the TPL standards and what is required per the reliability directive in Order 729. The TPL standards allow system operator intervention for category C3 contingencies between the two independent Category B contingencies. This standard should not exceed those requirements in the TPL standards. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test “must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning.” Paragraph 80 states that “the test must be consistent with the general reliability principles embedded in the existing series of TPL” standards. Thus, exceeding the TPL standards could be argued as deviating from the directive. We continue to believe that if the system as currently designed meets the performance requirements in TPL-003-0a R1 which allows for operator intervention on Category C3 contingencies, then the subject facilities would not be included in the PRC-023-2 R6 list of facilities. For those C3 contingencies that don’t currently meet the performance obligations after operator interventions, the subject facilities would be included in the PRC-023-2 R6 list of facilities. 3. We do not believe requirement R4 is needed. Limiting a relay setting to 115% of the associated transmission line’s highest seasonal 15 minute rating does not equate to a line that will trip before the operator has time to intervene. It does not mean the line will trip in 15 minutes. In fact, the operator should be taking action well in advance of reaching a 15 minute limit and the operator is likely only using the 15 minute rating in extreme circumstances. Furthermore, the

Voter	Entity	Segment	Vote	Comment
				operator will have more than 15 minutes to act with a setting 115% above the 15-minute rating. 4. We continue to believe PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. Contrary to the response of the drafting team to the last set of comments, the communication of facility ratings should include the time associated with the rating. Thus, if a facility is limited to 15 minutes or 30 minutes or any other finite amount of time, it should be included in the information communicated about facility ratings. Because FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator, this information regarding the time associated with the limitation should be communicated. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology. If the drafting team believes communication of additional information regarding ratings needs to be made clearer, the proper place to make the refinement would be in FAC-008-1 and FAC-009-1 not in PRC-023. 5. We disagree with the drafting team's assertion in response to the previous set of comments that Requirement 5 is an equally effective way to request data as a Section 1600 data request. First, Section 1600 was specifically written to collect data and that is its main intent. Ending a Section 1600 data request is relatively easy as NERC and the Regions could simply stop collecting the data without any compliance impact on the registered entities. Given the relative value of this data collection on a long term basis, it is highly likely that NERC and the Regional Entities will decide at some point that this data is no longer needed. Secondly, a requirement creates a continuing data request that is subject to sanctions even if the Regional Entities agree that data is no longer needed. Further, changing standards is no easy task given the amount of changes in the queue. The Standards Committee has recently implemented a prioritization tool and plan to limit work on standards to the top 12 or so priorities. There is a good chance seeking a change to eliminate a data request would not be considered a high priority and would result in a significant delay in terminating the data request. Thirdly, this is an administrative/paper compliance type of requirement that provides no direct reliability value. It is exactly the type of requirement that was discussed during the recent FERC Technical Conference on February 8 and that everyone seemed to agree needs to be prioritized out. 6. Attachment B describes the sub-100 kV facilities that the Planning Coordinator

Voter	Entity	Segment	Vote	Comment
				must consider in its assessment as those included in the Regional Entities critical facilities list. We know of no Regional Entity with such a list and there is no requirement for them to develop such a list. This could create the potential for a Planning Coordinator to be in violation because the Regional Entity has not completed its critical facilities list. This is clearly a conflict of interest sine the Regional Entity also monitors compliance and enforces the standards.

Response: Thank you for your comments.

1. The drafting team acknowledges that reliability-based needs for flowgates include concerns other than preventing instability, uncontrolled separation, or cascading. As noted in the NERC Glossary, "Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits." Thus a Flowgate based on Facility Ratings that is not required to prevent instability, uncontrolled separation, or cascading, but may be based on another reliability need. This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. While the IDC may be used to manage congestion in an equitable manner, the drafting team maintains that when the need to manage congestion is based on Facility Ratings or voltage or stability limits, the underlying issue being addressed is system reliability. To the extent that Flowgates are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates.
2. The drafting team believes the test in Attachment B achieves the directive in Order 733 (we believe this is the Order to which the commenter refers) and that deviations from the TPL standards are necessary and appropriate to address concerns stated by FERC, and that such deviations are not precluded by the Order. Specifically, the test identified in criterion B4 is consistent with, and developed specifically to address, the reliability concern driving the need for this standard. System disturbances in which relay loadability was a contributing factor, such as occurred on August 14, 2003, involve multiple contingencies without sufficient time for operator action. The drafting team notes that if manual adjustments were allowed between contingencies in criterion B4, this criterion would not identify any circuits subject to this standard except in cases where TPL-003 is violated. The test appropriately identifies circuits that may be loaded to levels that challenge relay settings when multiple contingencies occur. When such circuits are identified the Facility owner is required to meet relay loadability requirements to prevent the circuit from tripping unnecessarily before an operator has time to take corrective action. The drafting team respectfully points out that the Facility owner is not required to take any action to prevent overloads from occurring under such circumstances; the Facility owner is required only to provide relay loadability per the requirements in PRC-023 to mitigate the potential for such N-2 contingencies from leading to instability, uncontrolled separation, or cascading outages.
3. Requirement R4 has been included to address the FERC concerns stated in Order 733 and to comply with the associated directive. Providing this information to the specified entities addresses the potential for confusion as to the amount of time available to take corrective action.
4. While communicating a Facility Rating would include the time duration associated with the rating, requirements for transmitting the rating do not include any information as to whether the rating is based on a relay setting. The consequences of exceeding a Facility Rating typically follow an inverse-time characteristic; however, when a relay loadability limit is exceeded the circuit may trip in time on the order of

Voter	Entity	Segment	Vote	Comment
1 second or less, making it important that this information be communicated. Requirements in FAC-008-1 and FAC-009-1 do not require communication of the information addressed in Requirements R3 and R4 of PRC_023-2. The drafting team further notes that Requirement R3 is unchanged from the approved PRC-023-1 Requirement R2 (with the exception of minor formatting) and that inclusion of the new Requirement R4 was directed in Order 733 to addresses stated concerns. 5. The drafting team disagrees with the commenter and reasserts that Requirement R5 is an equally effective way to request this data. 6. The proposed standard requires Planning Coordinators to apply the criteria in Attachment B to all facilities operated below 100 kV that are on a critical facilities list. The drafting team believes the Planning Coordinator would not be in violation of the standard circuits have been identified by the Regional Entity <u>and</u> the Planning Coordinator failed to apply the criteria. However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES".				
Rebecca Berdahl	Bonneville Power Administration	3	Negative	1. BPA believes that there is a major discontinuity in the logical flow of the standard. As described in Section 4.2, the standard applies to certain transmission lines and transformers. In Requirement R1, there are thirteen criteria to select from "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". Of these thirteen criteria, only two apply to transformers--number ten and eleven. The way that these two are buried in between the other criteria that apply to line terminals and the way that they are written creates a question as to whether they apply to all transformers or only to transformers that are part of a transformer-terminated line. Additionally, since they are part of the group of thirteen criteria, of which only one must be selected, it appears that criteria ten and eleven can be ignored if another criterion is selected for a transformer-terminated line. BPA forsees this issue causing enough confusion among auditors and transmission owners that we cannot vote in favor of the standard until it is remedied. It would clear up the confusion if Criterion 10 was separated into two parts: one part that deals only with transmission line relays for transformer-terminated lines, and a second part that deals with load-responsive transformer relays. The second part--that deals with load-responsive transformer relays--should be moved along with Criterion 11 into a new requirement. This way, all of the criteria in Requirement 1 will apply only to line relays, with only one of the criteria needed to ensure that the line relays will not limit transmission system loadability. The new requirement (suggest using R2 and bumping the other requirements up a number) would deal specifically with load responsive transformer relays. Because this requirement would not be

Voter	Entity	Segment	Vote	Comment
				intermingled among the 13 optional criteria of Requirement 1, it would be clear that all load responsive transformer relays--not just those for transformer-terminated lines--were required to comply. 2. The drafting team has cleared up a major issue with Criterion 10.1 of Requirement 1 by clarifying that load responsive transformer relays must not expose a transformer to fault levels and durations that exceed the transformers mechanical withstand capability. This makes the requirement achievable, while the earlier version, which required that the relays not expose a transformer to fault levels and durations that exceeded its capability, was not. However, the mechanical withstand capability is not a well defined value, and the drafting team's use of a footnote to clarify this requirement is not sufficient. BPA agrees with the use of IEEE C57.109-1993 as the best way to define mechanical withstand capability, but if this is to be used as the measure of this requirement, it should be written into the requirement and not merely mentioned as a footnote. In addition, Clause 4.4, Figure 4 of IEEE C57.109-1993, as mentioned in the footnote, applies only to Category IV transformers. A close look at the standard reveals that the mechanical withstand capability curves for the other categories are not the same, and the requirements for these other categories must be identified as well.

Response: Thank you for your comments,

1. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that the structure of Requirement R1 is unchanged from the approved PRC-023-1 and is consistent with the “Zone 3” and “Beyond Zone 3” reviews completed by industry following the August 14, 2003 Northeast Blackout. The drafting team provided additional clarity specific to criterion 10 by splitting the fault protection aspect directed in the order (now part 10.1) from the relay loadability aspects. The drafting team believes that combining portions of criteria 10 and 11 at this time would add confusion by intermingling fault protective relays and overload relays. However, the drafting team will include your recommendations in the issues database for future consideration in the next general revision of the standard.

2. The drafting team believes that because the reference does not establish a requirement, rather it defines the phrase mechanical withstand capability, it is most appropriately included as a footnote rather than within Requirement R1, criterion 10. The drafting team also believes that a general citing of IEEE C57.109 within the requirements would be problematic in that we are only referencing a portion of the standard. The drafting team notes that the mechanical withstand is well-defined within the standard and that a specific reference to Clause 4.4, Figure from IEEE C57.109-1993 referenced in PRC-023-2 is sufficient. Category IV transformers are defined as transformers over 10,000 kVA (10 MVA) single-phase or 30,000 kVA (30 MVA) three-phase. Since this standard applies to BES facilities, the drafting team believes that the vast majority (if not all) of the applicable transformers will be Category IV transformers; if any Category III transformers fall within the applicability of this standard, the associated mechanical characteristic is virtually identical.

Voter	Entity	Segment	Vote	Comment
Gregg R Griffin	City of Green Cove Springs	3	Negative	From the last posting to this posting, for COM-002-3 R2, the phrase "the accuracy of the message has been confirmed" was added to the second step of three part communication. "Accuracy" is not the correct term here. "Understanding" is a better term. It would seem that "accuracy" is a term to be used in R3, the third part of the 3-part communication so that the issuer of the directive ensures the accuracy of the recipients understanding. FMPA suggests changing COM-002-3 R2 to read: Each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider, Load-Serving Entity, Distribution Provider, and Purchasing-Selling Entity that is the recipient of a Reliability Directive issued per Requirement R1, shall repeat, restate, rephrase or recapitulate the Reliability Directive with enough details to clearly communicate the recipient's understanding of the Reliability Directive.. The term "accuracy" can be interpreted as requiring the recipient to second-guess the Reliability Directive of the RC to enure the accuracy of the RC's directive in the first place. Under tight time constraints of Emergencies, this is not practical. We are sure that was not the intent of the drafting team. For IRO-001-2, FMPA does not see a need for R1. Doesn't the ERO already have that authority to establish RC's through the registration process, and to certify system operators through the PER standards? IRO-014-2 R5, "impacted" was replaced with "other". Wouldn't it be better to at least limit the notification to within the same interconnection? Or is R5 truly to identify all NERC registered RC's? More minor comments / suggestions for improvement: IRO-002 R2 can be improved by replacing "prevent identified events" with "prevent anticipated events". "Anticipated" aligns better with contingency analysis than "identified" IRO-005-4 R1 and R2 can be improved by replacing "expected" with "anticipated". Contingencies are not necessarily "expected"; however, we do "anticipate" them.
Response: Thank you for your comments. It appears that your comments pertain to Project 2006-06 – Reliability Coordination. The formal comment period for Project 2006-06 is open through March 7, 2011. Please submit your comments through the NERC website.				
Michelle A Corley	Cleco Corporation	3	Negative	Section 4.2 establishes the conditions to ultimately include the entire electric power infrastructure under the umbrella of protecting the "bulk electric system" which was originally defined as 200kV and above. Cleco is concerned this ever expanding regulatory umbrella is not justified.
Response: Thank you for your comment. The drafting team believes that Section 4.2 will identify only those circuits that if they trip due to relay loadability, may contribute to undesirable system performance similar to what occurred during the August 14, 2003 blackout. The criteria developed in Attachment B were developed to				

Voter	Entity	Segment	Vote	Comment
achieve this purpose. To the extent the commenter is concerned with the reference to facilities operated below 100 kV, the drafting team points out that consistent with the FERC position in Order 733-A we expect that references to circuits operated below 100 kV will have narrow applicability. The drafting team also notes that to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this the reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES."				
Henry Ernst-Jr	Duke Energy Carolina	3	Affirmative	Duke agrees with the substance of the changes to PRC-023-2, but believe that compliance questions will arise when entities have to sort out the relationship between Section 4.2, Requirement R6 and Attachment B Criteria B5 and B6. Clarifying changes should be made. For example, add the phrase "in accordance with R6" to 4.2.1.2 and 4.2.1.5, then delete 4.2.2, 4.2.2.1 and 4.2.2.2 entirely, and finally, change B5 to the way it was in the last draft, and delete B6.
Response: Thank you for your comments. The drafting team agrees that the phrase "in accordance with R6" should have been included in Applicability Sections 4.2.1.2 and 4.2.1.5 the same as Sections 4.2.1.3 and 4.2.1.6 and has made this modification. The drafting believes that Section 4.2.2 should remain as this section differentiates that the set of circuits to which the Planning Coordinator must apply the criteria in Attachment B is a larger set than the set of circuits for which Facility owners must comply with Requirements R1 through R5 of PRC-023-2. The drafting team modified criterion B5 to include consultation with the Facility owner to allow the Facility owner an opportunity to provide insight to the Planning Coordinator performing the analysis. By involving the Facility owner during the Planning Coordinator assessment, the likelihood that the Facility owner will need to utilize the appeals process in Section 1700 of the NERC Rule of Procedure is reduced. The drafting team expects that the added criterion B6 will have limited applicability, but it does address a concern raised by commenters during the previous posting. Given that both parties must mutually agree, the drafting team believes there is no potential for undue compliance burden as a result of retaining this criterion.				
Kevin Querry	FirstEnergy Solutions	3	Affirmative	We applaud the drafting team for their diligent and expeditious work on responding to the FERC directives of Order 733. We support the standard but ask that the team clarify the effective dates. Compliance Application Notice CAN-0013 which was recently posted for industry comment correctly adds clarification to the actual effective date for (1) Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System; (2) Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System; and (3) Switch-on-to-fault schemes on all applicable facilities. Since this CAN specifies the date of October 1, 2013 in the U.S., we ask that the following sections of PRC-023-2 be revised to include this date: "5.1.1.1.3 For switch-on-to-

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td></td><td>fault schemes as described in PRC-023-2 - Attachment A, Section 1.3, the later of the first day of the first calendar quarter after applicable regulatory approval of PRC-023-2 or the first day of the first calendar quarter 39 months following applicable regulatory (October 1, 2013 in the U.S.) approval of PRC-023-1; or in those jurisdictions where no regulatory approval is required, the later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011." and "5.1.2.1 The later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator (October 1, 2013 in the U.S.) 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."</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.

The drafting team acknowledges the complexity involved in the effective dates for this standard. The drafting team has reformatted the Effective Dates section of the standard into a tabular format consistent with CAN-0013 and has inserted the US effective date (October 1, 2013) where appropriate.</td></tr>
<tr><td>Charles Locke</td><td>Kansas City Power & Light Co.</td><td>3</td><td>Negative</td><td>1. The criteria with Attachment B is not consistent with the TPL planning standards and is likely to identify transmission facilities that do not pose a reliability threat to the operation of the interconnection. The criteria in Attachment B should focus on identifying transmission facilities that play a reliability role in maintaining equipment loadings within SOL and IROL facility ratings and not include other considerations such as flowgates which are a mechanism for energy market management.
2. In addition, the implementation time frames specified are not clear whether the implementation time frame of 24 months is an extension from the 18 month time frame for the RC to identify circuits using the criteria in Attachment B or if the 24 months is concurrent with the 18 months. Also, it is uncertain whether the 24 months will be sufficient without knowing the impact of the RC analysis.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.

1. The criteria identified in Attachment B are consistent with, and developed specifically to address, the reliability concern driving the need for this standard. The drafting team continues to believe that Flowgates addressing reliability concerns for loading of circuits is an appropriate inclusion in these criteria. As noted in the NERC Glossary, "Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits." This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. To the extent that Flowgates</td></tr>
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<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td colspan="5">are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates.

2. The drafting team believes the commenter is referring to the time provided to a Facility owner to comply with PRC-023 after the Planning Coordinator identifies a circuit is subject to PRC-023-2 per application of Attachment B. The drafting team notes that in the previous posting of the standard this timeframe was extended from 24 months to 39 months. Specific to the commenter’s question, the standard identifies the 39 months are measured from “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.” The 39 months in neither concurrent with nor an extension of the 18 months provided to the Planning Coordinator.</td></tr>
<tr><td>Gregory David Woessner</td><td>Kissimmee Utility Authority</td><td>3</td><td>Negative</td><td>The Regional Entity is not the correct entity to make decisions concerning what < 100 kV equipment is critical or not. It is too subject to inconsistent criteria being applied across the continent. It also is not in alignment with the regulatory construct of a stakeholder process described in Section 215 of the Federal Power Act which affords us the opportunity to learn from each other and develop better answers and solutions that appropriately balance costs, benefits and risks. Development of criteria and the application of that criteria ought to be a collaborative process continent-wide such that the criteria are applied consistently across the continent. This can be done separately, or as part of the BES definition effort currently underway. In the interim, many regions have Planning Coordinators that are not self-regulating, e.g., the Planning Coordinator is separate from the asset owners. Most of the Planning Coordinators are stakeholder organization whose "Planning Committees" would make the determination. For entities that do self-regulate, e.g., they are both the asset owner and Planning Coordinator, presumably the Regional Entity could form a stakeholder process with a Planning Committee whose members include appropriate and balanced representation from the stakeholders. These "Planning Committees" could be an alternative source for a stakeholder process to determine criteria for < 100 kV Applicability and apply that criteria while a continent-wide effort is underway to determine that criteria. These "Planning Committees" could remain in place to apply the continent-wide criteria to the regional system.</td></tr>
<tr><td colspan="5">Response: Thank you for your comment.

The drafting team notes that PRC-023 does not grant the Regional Entity any authority, rather it reflects language already contained in the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list entities that do not own or operate “a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity (emphasis added).” However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are “part of the BES”.</td></tr>
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Voter	Entity	Segment	Vote	Comment
Greg C. Parent	Manitoba Hydro	3	Negative	Please see comments previously submitted by Manitoba Hydro regarding the effective date and the items included in Section 1.6 of Attachment A.
Response: Thank you for your comments. 1. The drafting team has considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1. Extending the timeframe included consideration of the number of circuits that may be identified by the Planning Coordinator. 2. Items included in Section 1.6 of Attachment A are included to address the concerns noted by FERC in Order 733. Settings for the protection schemes of concern are often very sensitive – well below load current – and dependent on the integrity of the communication channel to make a trip/no trip decision where other telecommunication system technologies require the operation of other protection system elements (usually distance elements) which are already subject to the requirements of this standard. Therefore, they will trip immediately due to load current upon the loss of communications, and are dependent on the fault detectors to inhibit trip which must therefore be secure regardless of how infrequently loss of communications may occur.				
Thomas C. Mielnik	MidAmerican Energy Co.	3	Negative	1. The Attachment B5 criteria determining critical facilities appears to be wide open and eliminates the facility planner/owner's authority to determine what are and are not "critical" facilities on its own system based upon wording in Attachment B. To give one entity, the Planning Coordinator, the power to assign the designation of "critical" potentially over a facility planners/owners objection based upon any study or study criteria the Planning Coordinator decides is valid is inappropriate and also potentially result in reduced reliability. There may be issues that the Transmission Planner may know about or know more about that the Planning Coordinator does not. Criteria B5 should be deleted. If B5 is not deleted, a minimum, the B5 wording "in consultation with" should be replaced with "upon mutual agreement with". The facility planner/owner who best understands its facilities should have some final say in conjunction with its Planning Coordinator in determining what is and is not critical to its system and the region. 2. The drafting team change in Attachment B1 of adding the word "permanent" in front of "flowgate" did not correct the fundamental issue that a "flowgate" is not by definition a reliability issue and has no more measurable risk than the loss of any other BES transmission element. An example is the loss of a 161 kV flowgate, might have less reliability impact than the loss of a 345 or 500 kV line that is not designated as a flowgate. Therefore the criteria to define a "critical" facility through a flowgate designation is fundamentally in error. A better definition of "critical" is if the loss of a transmission element results in instability,

Voter	Entity	Segment	Vote	Comment
				uncontrolled separation, and cascading as defined in the Federal Power Act.
Response: Thank you for your comments. 1. The authority for identifying circuits below 200 kV for which Facility owners must comply with PRC-023-2 is assigned to the Planning Coordinators in PRC-023-1. The drafting team believes that criterion B5 in Attachment B of PRC-023-2 is not wide-open because it requires that the determination must (i) be based on technical studies or assessments and (ii) must be made in consultation with the Facility owner. While the drafting team understands the need for Facility owner input, we also believe it is inappropriate to give the Facility Owner de facto veto power by using the phrase “upon mutual agreement with.” We believe the Planning Coordinator will give due consideration to the Facility owner’s input, and in cases where the Facility owner disagrees with the determination of the Planning Coordinator, they are free to use the appeals process in Section 1700 of the NERC Rules of Procedure that was developed to address this concern. 2. As noted in the NERC Glossary, “Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits.” This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. To the extent that Flowgates are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates.				
John S Bos	Muscatine Power & Water	3	Affirmative	How does the STD feel about the possibility of conflicts between the Planning Coordinator and the Facility Owner pertaining to B5? How would these unforseen conflicts be resolved?
Response: Thank you for your comment. As directed in ¶97 of Order 733, NERC has developed an appeals process so that Facility owners may challenge the determination of the Planning Coordinators. The appeals process will be contained in Section 1700 of the NERC Rules of Procedure.				
Michael Schiavone	Niagara Mohawk (National Grid Company)	3	Affirmative	1. List of Critical Facilities: Since a critical facilities list would be prepared for other reasons (e.g. CIP-002), National Grid is assuming that the list of critical facilities will be reviewed for applicability to PRC-023 and that a subset of the list may need to be defined for this application. 2. There appears to be inconsistency in the wording pertaining to the sentence - "critical facilities list defined by the Regional Entity and selected by the Planning Coordinator". In 4.2.1.3 the aforementioned sentence is produced in its entirety. However, in attachment B, under Circuits to Evaluate, bullet point 2, the sentence is missing "...and selected by the Planning Coordinator". This piece is also missing in 4.2.2.2. 3. Attachment B, B4 a.: National Grid requests the drafting team to explain the rationale behind deleting "Category C3" from B4. National Grid believes that by

Voter	Entity	Segment	Vote	Comment
				providing reference to Category C3, the standard focuses on the scope and provides for consistency in the engineering judgment. However, by deleting Category C3, the scope becomes undefined as to the level of combinations that need to be assessed and will concern the engineer that his engineering judgment can be called into question. 4. Summary consideration on pg. 1 regarding supervisory elements associated with current based, communication assisted schemes having to meet PRC-023-2 and inclusion of such elements in Attachment A, 1.6: This is taken to mean line differential schemes. If the supervisory elements for a line diff must be set high enough to comply with PRC-023-2 that will make the entire scheme extremely insensitive to faults. For example R1.1 would require the supervising elements be set > 1.5 x the 4 hr. loading meaning the scheme will be unable to detect an internal fault unless it exceeds 1.5 x the 4 hr. loading. That negates one of the chief advantages of using a line differential scheme in the first place, specifically it's sensitivity. If the communications for a relay scheme is lost the scheme is essentially "broken" and to require it to still function correctly per PRC-023-2 even when broken is unreasonable. There is no requirement that distance schemes conform to PRC-023-2 if they are broken, for example if they lose their restraint potential they will trip on load too. 5. Switch on to fault scheme included in Attachment A, 1.3 - An exception needs to be added for those schemes that are smart enough to detect a live line condition and which are disabled when closing or reclosing into an already energized line. Such schemes will not respond to current flow into and through a live line. Requiring that such a SOTF scheme that can recognize a live line be set to carry through current regardless, negates the advantage of the scheme in the first place, specifically its sensitivity. 6. Regarding R1, Criterion 10 - What if the transformer at the end of the line has its own overcurrent protection that either trips a local high side breaker or circuit switcher or TT's the other end of the source line and this transformer overcurrent protection is set below the mechanical damage curve. Must the line protection back at the source to the line still be set below the transformer's mechanical damage curve? If your answer is yes, what if the line protection is step distance with a flat timer, like a zone 2 timer. Coordinating a zone 2 looking into the transformer and having a flat zone 2 timer against and inverse transformer mechanical damage curve is awkward at best and maybe not even feasible. 7. Regarding R1, Criterion 5 - "Weak source system" is a relative term. Is the reader free to define "weak" as the reader chooses? If not then it needs to be

Voter	Entity	Segment	Vote	Comment
				defined in the standard.

Response: Thank you for your comments.

1. Yes, additional screening will be applied. The Planning Coordinator is required to apply the criteria in Attachment B to these facilities to identify which circuits on the list are relevant to the reliability objective of PRC-023-2.
2. These differences are intentional. Where the phrase is not included it is referring to the circuits that must be evaluated by the Planning Coordinator. The Planning Coordinator must apply the criteria in Attachment B to all facilities operated below 100 kV that are on a critical facilities list. However, the Facility owners are required to comply with PRC-023-2 only for those circuits selected by the Planning Coordinator in accordance with Requirement R6.
3. The reference to category C3 contingencies resulted in confusion with some entities because the test required in criterion B4 is not the same as category C3 since criterion B4 does not include manual system adjustments between contingencies.
4. Items included in Section 1.6 of Attachment A are included to address the concerns noted by FERC in Order 733. Settings for the protection schemes of concern are often very sensitive – well below load current – and dependent on the integrity of the communication channel to make a trip/no trip decision where other telecommunication system technologies require the operation of other protection system elements (usually distance elements) which are already subject to the requirements of this standard. Therefore, they will trip immediately due to load current upon the loss of communications, and are dependent on the fault detectors to inhibit trip which must therefore be secure regardless of how infrequently loss of communications may occur.
5. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that Attachment A, Section 1.3 is unchanged from the approved PRC-023-1. However, the drafting team will include your recommendations in the issues database for future consideration in the next general revision of the standard.
6. No, in the previous posting the drafting team separated the relay loadability aspect and the transformer fault protection aspect of criterion 10. The transformer fault protection relays and transmission line relays both must meet the relay loadability requirements listed in the two bullets in criterion 10. Only the transformer fault protection relays, if used, must be coordinated with the transformer mechanical withstand capability.
7. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that Requirement R1, criterion 5 is unchanged from the approved PRC-023-1. Entities may apply criterion 5 to any line, although when the source becomes sufficiently strong this criterion will become more restrictive than others.

Voter	Entity	Segment	Vote	Comment
David Schiada	Southern California Edison Co.	3	Negative	We do not feel that the concerns raised in comments on the last round of balloting have been adequately addressed. Among the concerns still remaining are the use of "critical facilities" in several of the requirements and the respective roles that Regional Entities and Planning Coordinators will play in identifying critical facilities.

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td colspan="5"> Response: Thank you for your comments. The Regional Entity may develop a list of critical facilities by means outside this standard. The reference to a list of critical facilities in PRC-023-2 is in the same context as the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list an entity that does not own or operate “a transmission element below 100 kV associated with <u>a facility that is included on a critical facilities list that is defined by the Regional Entity</u> (emphasis added).” To provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has replaced the reference to a “list of critical facilities” with a reference to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are “part of the BES.” The role of the Planning Coordinator is defined in Requirement R6. The Planning Coordinator will be required to apply the criteria in Attachment B in accordance with Requirement R6 of PRC-023-2 to identify any circuits on the list for which the Facility owner must comply with PRC-023-2. </td></tr>
<tr><td>Ian S Grant</td><td>Tennessee Valley Authority</td><td>3</td><td>Affirmative</td><td>For Attachment B part B1: “Permanent flowgate” is too ambiguous. Most entities in the eastern interconnect use flowgates in many different processes such as EMS systems and state estimator, transfer capability calculations, congestion management processes, and market calculations. All of these processes have flowgates that could be considered “permanent”. If this standard is pointing to the IDC Book of Flowgate (BOF) Permanent flowgates, then this should be so stated. However, since the IDC BOFs is not the most up to date list of flowgates, we suggest that a better line criticality identification to reliability is if a TLR has been called on the flowgate in the last two year. We recommend that instead of “permanent flowgate”, the B1 portion of Attachment B1 should say “ in the IDC Book of Flowgates and a TLR 3 or greater has been called on the flowgate in the last two years”.</td></tr>
<tr><td colspan="5"> Response: Thank you for your comments. The drafting team appreciates the suggestion to further refine the Flowgates of interest in the context of criterion B1. However, the drafting team believes that the Flowgates of interest must be determined based on the reliability basis for adding the Flowgate rather than historical transfers. Even if a TLR has not been called on a Flowgate for an extended period of time, during a system disturbance an overload on a monitored Facility comprising the Flowgate could lead to cascading outages if relay loadability requirements are not met. The drafting team believes it is best to continue to refer to circuits that are monitored Facilities of Flowgates that are included to address reliability concerns for loading of those circuits. </td></tr>
<tr><td>David Frank Ronk</td><td>Consumers Energy</td><td>4</td><td>Negative</td><td>As a Generator Owner dependent on a Transmission Provider, access to information about the transmission relays seems to be required for us to comply with this proposed Standard. It does not seem that the Transmission Provider is required to furnish us this information. Requiring information transfer without writing it into the Standard places us in needless jeopardy.</td></tr>
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Voter	Entity	Segment	Vote	Comment
Response: Thank you for your comment. As described in the Applicability section of the standard, Generator Owners are only subject to compliance with Requirements R1 through R5 to the extent they own load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1. If a Generator Owner owns such relays they should have information available necessary to set the relays and confirm relay loadability requirements are met.				
Frank Gaffney	Florida Municipal Power Agency	4	Negative	The Regional Entity is not the correct entity to make decisions concerning what < 100 kV equipment is critical or not. It is too subject to inconsistent criteria being applied across the continent. It also is not in alignment with the regulatory construct of a stakeholder process described in Section 215 of the Federal Power Act which affords us the opportunity to learn from each other and develop better answers and solutions that appropriately balance costs, benefits and risks. Development of criteria and the application of that criteria ought to be a collaborative process continent-wide such that the criteria are applied consistently across the continent. This can be done separately, or as part of the BES definition effort currently underway. In the interim, many regions have Planning Coordinators that are not self-regulating, e.g., the Planning Coordinator is separate from the asset owners. Most of the Planning Coordinators are stakeholder organization whose "Planning Committees" would make the determination. For entities that do self-regulate, e.g., they are both the asset owner and Planning Coordinator, presumably the Regional Entity could form a stakeholder process with a Planning Committee whose members include appropriate and balanced representation from the stakeholders. These "Planning Committees" could be an alternative source for a stakeholder process to determine criteria for < 100 kV Applicability and apply that criteria while a continent-wide effort is underway to determine that criteria. These "Planning Committees" could remain in place to apply the continent-wide criteria to the regional system.
Response: Thank you for your comment. The drafting team notes that PRC-023 does not grant the Regional Entity any authority, rather it reflects language already contained in the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list entities that do not own or operate "a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity (emphasis added)." However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES."				
Thomas W. Richards	Fort Pierce Utilities	4	Negative	The Regional Entity is not the correct entity to make decisions concerning what < 100 kV equipment is critical or not. It is too subject to inconsistent criteria being

Voter	Entity	Segment	Vote	Comment
	Authority			applied across the continent. It also is not in alignment with the regulatory construct of a stakeholder process described in Section 215 of the Federal Power Act which affords us the opportunity to learn from each other and develop better answers and solutions that appropriately balance costs, benefits and risks. Development of criteria and the application of that criteria ought to be a collaborative process continent-wide such that the criteria are applied consistently across the continent. This can be done separately, or as part of the BES definition effort currently underway. In the interim, many regions have Planning Coordinators that are not self-regulating, e.g., the Planning Coordinator is separate from the asset owners. Most of the Planning Coordinators are stakeholder organization whose "Planning Committees" would make the determination. For entities that do self-regulate, e.g., they are both the asset owner and Planning Coordinator, presumably the Regional Entity could form a stakeholder process with a Planning Committee whose members include appropriate and balanced representation from the stakeholders. These "Planning Committees" could be an alternative source for a stakeholder process to determine criteria for < 100 kV Applicability and apply that criteria while a continent-wide effort is underway to determine that criteria. These "Planning Committees" could remain in place to apply the continent-wide criteria to the regional system.
Response: Thank you for your comment. The drafting team notes that PRC-023 does not grant the Regional Entity any authority, rather it reflects language already contained in the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list entities that do not own or operate "a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity (emphasis added)." However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES."				
Bob C. Thomas	Illinois Municipal Electric Agency	4	Negative	Illinois Municipal Electric Agency (IMEA) appreciates the SDT's efforts to include provisions which distinguish applicability to < 100 kV lines and transformers on a critical facilities list. IMEA supports comments to this effect as submitted by Florida Municipal Power Agancy.
Response: Thank you for your comment. The drafting team notes that PRC-023 does not grant the Regional Entity any authority, rather it reflects language already contained in the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list entities that do not own or operate "a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity (emphasis added)." However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under				

Voter	Entity	Segment	Vote	Comment
development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES."				
Douglas Hohlbaugh	Ohio Edison Company	4	Affirmative	We applaud the drafting team for their diligent and expeditious work on responding to the FERC directives of Order 733. We support the standard but ask that the team clarify the effective dates. Compliance Application Notice CAN-0013 which was recently posted for industry comment correctly adds clarification to the actual effective date for (1) Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System; (2) Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System; and (3) Switch-on-to-fault schemes on all applicable facilities. Since this CAN specifies the date of October 1, 2013 in the U.S., we ask that the following sections of PRC-023-2 be revised to include this date: "5.1.1.1.3 For switch-on-to-fault schemes as described in PRC-023-2 - Attachment A, Section 1.3, the later of the first day of the first calendar quarter after applicable regulatory approval of PRC-023-2 or the first day of the first calendar quarter 39 months following applicable regulatory (October 1, 2013 in the U.S.) approval of PRC-023-1; or in those jurisdictions where no regulatory approval is required, the later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011." and "5.1.2.1 The later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator (October 1, 2013 in the U.S.) 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."
Response: Thank you for your comments. The drafting team acknowledges the complexity involved in the effective dates for this standard. The drafting team has reformatted the Effective Dates section of the standard into a tabular format consistent with CAN-0013 and has inserted the US effective date (October 1, 2013) where appropriate.				
Brock Ondayko	AEP Service Corp.	5	Affirmative	The wording of Attachment A, section 1.6 should be made consistent to avoid any confusion. AEP suggests that it be reworded to read: "Supervisory elements used as fault detectors associated with pilot wire or current differential protection systems where the system is capable of tripping for loss of communications".

Voter	Entity	Segment	Vote	Comment
Response: Thank you for your comments. The drafting team apologizes for confusion regarding Attachment A, Section 1.6 during the previous posting. The drafting team had intended to provide additional clarification. The drafting team has inserted parenthetical statements to clarify that the phrase “phase overcurrent supervisory elements” refers to phase fault detectors and “current-based communication-assisted schemes” refers to pilot wire, phase comparison, and line current differential schemes. We believe this modification is in-line with your recommended modification.				
Francis J. Halpin	Bonneville Power Administration	5	Negative	1. BPA believes that there is a major discontinuity in the logical flow of the standard. As described in Section 4.2, the standard applies to certain transmission lines and transformers. In Requirement R1, there are thirteen criteria to select from "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". Of these thirteen criteria, only two apply to transformers--number ten and eleven. The way that these two are buried in between the other criteria that apply to line terminals and the way that they are written creates a question as to whether they apply to all transformers or only to transformers that are part of a transformer-terminated line. Additionally, since they are part of the group of thirteen criteria, of which only one must be selected, it appears that criteria ten and eleven can be ignored if another criterion is selected for a transformer-terminated line. BPA forsees this issue causing enough confusion among auditors and transmission owners that we cannot vote in favor of the standard until it is remedied. It would clear up the confusion if Criterion 10 was separated into two parts: one part that deals only with transmission line relays for transformer-terminated lines, and a second part that deals with load-responsive transformer relays. The second part--that deals with load-responsive transformer relays--should be moved along with Criterion 11 into a new requirement. This way, all of the criteria in Requirement 1 will apply only to line relays, with only one of the criteria needed to ensure that the line relays will not limit transmission system loadability. The new requirement (suggest using R2 and bumping the other requirements up a number) would deal specifically with load responsive transformer relays. Because this requirement would not be intermingled among the 13 optional criteria of Requirement 1, it would be clear that all load responsive transformer relays--not just those for transformer-terminated lines--were required to comply. 2. The drafting team has cleared up a major issue with Criterion 10.1 of Requirement 1 by clarifying that load responsive transformer relays must not expose a transformer to fault levels and durations that exceed the transformers mechanical withstand capability. This makes the requirement achievable, while

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				the earlier version, which required that the relays not expose a transformer to fault levels and durations that exceeded its capability, was not. However, the mechanical withstand capability is not a well defined value, and the drafting team's use of a footnote to clarify this requirement is not sufficient. BPA agrees with the use of IEEE C57.109-1993 as the best way to define mechanical withstand capability, but if this is to be used as the measure of this requirement, it should be written into the requirement and not merely mentioned as a footnote. In addition, Clause 4.4, Figure 4 of IEEE C57.109-1993, as mentioned in the footnote, applies only to Category IV transformers. A close look at the standard reveals that the mechanical withstand capability curves for the other categories are not the same, and the requirements for these other categories must be identified as well.
Response: Thank you for your comments. 1. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that the structure of Requirement R1 is unchanged from the approved PRC-023-1 and is consistent with the “Zone 3” and “Beyond Zone 3” reviews completed by industry following the August 14, 2003 Northeast Blackout. The drafting team provided additional clarity specific to criterion 10 by splitting the fault protection aspect directed in the order (now part 10.1) from the relay loadability aspects. The drafting team believes that combining portions of criteria 10 and 11 at this time would add confusion by intermingling fault protective relays and overload relays. However, the drafting team will include your recommendations in the issues database for future consideration in the next general revision of the standard. 2. The drafting team believes that because the reference does not establish a requirement, rather it defines the phrase mechanical withstand capability, it is most appropriately included as a footnote rather than within Requirement R1, criterion 10. The drafting team also believes that a general citing of IEEE C57.109 within the requirements would be problematic in that we are only referencing a portion of the standard. The drafting team notes that the mechanical withstand is well-defined within the standard and that a specific reference to Clause 4.4, Figure from IEEE C57.109-1993 referenced in PRC-023-2 is sufficient. Category IV transformers are defined as transformers over 10,000 kVA (10 MVA) single-phase or 30,000 kVA (30 MVA) three-phase. Since this standard applies to BES facilities, the drafting team believes that the vast majority (if not all) of the applicable transformers will be Category IV transformers; if any Category III transformers fall within the applicability of this standard, the associated mechanical characteristic is virtually identical.				
James B Lewis	Consumers Energy	5	Negative	As a Generator Owner dependant on a Transmission Provider, access to information about the transmission relays seems to be required for us to comply with this proposed Standard. It does not seem that the Transmission Provider is required to furnish us this information. Requiring information transfer without writing it into the Standard places us in needless jeopardy.

Voter	Entity	Segment	Vote	Comment
Response: Thank you for your comment. As described in the Applicability section of the standard, Generator Owners are only subject to compliance with Requirements R1 through R5 to the extent they own load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1. If a Generator Owner owns such relays they should have information available necessary to set the relays and confirm relay loadability requirements are met.				
Rex A Roehl	Indeck Energy Services, Inc.	5	Negative	This standard should not apply to generators. To the extent that a particular generator qualifies for some of the requirements of this standard, they should be specially applied, as has been done by WECC for generators with long transmission lines. There are 820 GO and 780 GOP registered entities. It is unlikely that many of them qualify. It would take an expensive consultant a substantial amount of time to understand the standard such that a determination could be made for a GO/GOP if it qualified. This is an unnecessary burden. The applicability section should be modified as such.
Response: Thank you for your comments. As described in the Applicability section of the standard, Generator Owners are only subject to compliance with Requirements R1 through R5 to the extent they own load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1. In order to achieve the reliability objective of this standard, it is necessary for all entities that own such relays to meet the relay loadability requirements.				
Scott Heidtbrink	Kansas City Power & Light Co.	5	Negative	1. The criteria with Attachment B is not consistent with the TPL planning standards and is likely to identify transmission facilities that do not pose a reliability threat to the operation of the interconnection. The criteria in Attachment B should focus on identifying transmission facilities that play a reliability role in maintaining equipment loadings within SOL and IROL facility ratings and not include other considerations such as flowgates which are a mechanism for energy market management. 2. In addition, the implementation time frames specified are not clear whether the implementation time frame of 24 months is an extension from the 18 month time frame for the RC to identify circuits using the criteria in Attachment B or if the 24 months is concurrent with the 18 months. Also, it is uncertain whether the 24 months will be sufficient without knowing the impact of the RC analysis.
Response: Thank you for your comments. 1. The criteria identified in Attachment B are consistent with, and developed specifically to address, the reliability concern driving the need for this standard. The drafting team continues to believe that Flowgates addressing reliability concerns for loading of circuits is an appropriate inclusion in these criteria. As noted in the NERC Glossary, "Total Flowgate Capabilities are determined based on Facility Ratings and voltage				

Voter	Entity	Segment	Vote	Comment
and stability limits." This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. To the extent that Flowgates are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates. 2. The drafting team believes the commenter is referring to the time provided to a Facility owner to comply with PRC-023 after the Planning Coordinator identifies a circuit is subject to PRC-023-2 per application of Attachment B. The drafting team notes that in the previous posting of the standard this timeframe was extended from 24 months to 39 months. Specific to the commenter's question, the standard identifies the 39 months are measured from "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." The 39 months in neither concurrent with nor an extension of the 18 months provided to the Planning Coordinator.				
S N Fernando	Manitoba Hydro	5	Negative	Please see comments previously submitted by Manitoba Hydro regarding the effective date and the items included in Section 1.6 of Attachment A.
Response: Thank you for your comments. 1. The drafting team has considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1. Extending the timeframe included consideration of the number of circuits that may be identified by the Planning Coordinator. 2. Items included in Section 1.6 of Attachment A are included to address the concerns noted by FERC in Order 733. Settings for the protection schemes of concern are often very sensitive – well below load current – and dependent on the integrity of the communication channel to make a trip/no trip decision where other telecommunication system technologies require the operation of other protection system elements (usually distance elements) which are already subject to the requirements of this standard. Therefore, they will trip immediately due to load current upon the loss of communications, and are dependent on the fault detectors to inhibit trip which must therefore be secure regardless of how infrequently loss of communications may occur.				
Christopher Schneider	MidAmerican Energy Co.	5	Negative	1. Comment: The Attachment B5 criteria determining critical facilities appears to be wide open and eliminates the facility owner's authority to determine what are and are not "critical" facilities on its own system based upon wording in Attachment B. The word "critical" is used throughout other NERC standards and has many potential implications. To give one entity, the Planning Coordinator, the power to assign the designation of "critical" potentially over a facility owners objection based upon any study or study criteria the Planning Coordinator decides is valid is inappropriate. Criteria B5 should be deleted. If B5 is not deleted, a minimum, the B5 wording "in consultation with" should be replaced with "upon mutual agreement with". The facility owner who best understands its facilities should have some final say in conjunction with its Planning

Voter	Entity	Segment	Vote	Comment
				Coordinator in determining what is and is not critical to its system and the region. 2. The drafting team change in Attachment B1 of adding the word “permanent” in front of “flowgate” did not correct the fundamental issue that a “flowgate” is not by definition a reliability issue and has no more measurable risk than the loss of any other BES transmission element. An example is the loss of a 161 kV flowgate, might have less reliability impact than the loss of a 345 or 500 kV line that is not designated as a flowgate. Therefore the criteria to define a “critical” facility through a flowgate designation is fundamentally in error. A better definition of “critical” is if the loss of a transmission element results in instability, uncontrolled separation, and cascading as defined in the Federal Power Act. 3. Vote negative on the VSLs Nearly all the VSLs are a binary in nature resulting in a zero defect standard with a “severe” result. This is an incorrect usage of the VSL concept which was to show graduated levels of risk, not deterministic zero defect results. This incorrect enforcement concept actually slows reliability progress by delaying standard implementation and hurts the concept of the new “administrative ticket process”. FERC will be reluctant to allow the administrative ticket process to be used for a “severe” VSL violation even if it can be shown there was little to no BES risk.

Response: Thank you for your Comments.

1. The authority for identifying circuits below 200 kV for which Facility owners must comply with PRC-023-2 is assigned to the Planning Coordinators in PRC-023-1. The drafting team believes that criterion B5 in Attachment B of PRC-023-2 is not wide-open because it requires that the determination must (i) be based on technical studies or assessments and (ii) must be made in consultation with the Facility owner. While the drafting team understands the need for Facility owner input, we also believe it is inappropriate to give the Facility Owner de facto veto power by using the phrase “upon mutual agreement with.” We believe the Planning Coordinator will give due consideration to the Facility owner’s input, and in cases where the Facility owner disagrees with the determination of the Planning Coordinator they are free to use the appeals process in Section 1700 of the NERC Rules of Procedure that was developed to address this concern.

2. As noted in the NERC Glossary, “Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits.” This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. To the extent that Flowgates are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates.

3. Requirements R1 through R5 are similar in structure to Requirements R1 and R2 in the approved PRC-023-1. FERC directed binary VSLs for Requirements R1 and R2 in Order 733 and the drafting team believes binary VSLs for Requirements R1 through R5 in PRC-023-2 are

Voter	Entity	Segment	Vote	Comment
consistent with that Order.				
Michelle DAntuono	Occidental Chemical	5	Negative	1. Need justification as to why lines below 100 KV that are included on a critical facilities list defined by the Regional Entity are also processed through the Attachment B criteria list. The previous version did not consider lines below 100KV. 2. Attachment B still allows the PC to select facilities below 200KV based on criteria/studies other than specified in the rest of Attachment B, but requires this to be done "in consultation with the Facility owner." This prompts close scrutiny of the challenge process that is required under the FERC Order. This also causes Regional discrepancies, which NERC is trying to steer away from. There should be "bright line" across all Regions. 3. Need justification as to why the VSLs are listed as Severe. 4. There is required annual reporting, which begs the question of what is required of a Registered Entity that has nothing to report?
Response: 1. The drafting team modified Attachment B in response to industry comments. Based on comments during the previous posting, the drafting team believes it is appropriate to assess sub-100 kV circuits using the same methodology applied to circuits operated at 100 kV to 200 kV. Requiring applicable entities to comply for all sub-100 kV circuits included on a critical facilities list defined by the Regional Entity results in a higher standard for sub-100 kV circuits, and is inconsistent with the directive in ¶60 of Order No. 733. 2. Criteria B1 through B4 in Attachment B provide a consistent methodology for Planning Coordinators to apply across all regions. In recognition that these criteria may not identify every circuit that presents a risk of cascading outages if relay loadability requirements are not met, criteria B5 and B6 have been included. The drafting team believes that criteria B1 through B4 will identify the majority of circuits of concern, and that criteria B5 and B6 will be used only in unique cases that cannot be captured in a bright-line definition. 3. Requirements R1 through R5 are similar in structure to Requirements R1 and R2 in the approved PRC-023-1. FERC directed binary VSLs for Requirements R1 and R2 in Order 733 and the drafting team believes binary VSLs for Requirements R1 through R5 in PRC-023-2 are consistent with that Order. In the case of binary VSLs, the VSLs are set to Severe by definition. 4. Measures M4 and M5 have been updated to indicate that "The updated list may 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".				
Sandra L. Shaffer	PacifiCorp	5	Negative	1. PacifiCorp agrees with what it understands are the general concepts contained in Applicability Section 4.2, Requirements R6 and R7, and Attachment B of the proposed PRC-023-2. Namely, that: 1) the standard applies to all facilities (defined in Attachment A) above 200 kV and some facilities below 200 kV; 2) the Planning Coordinator is responsible for identifying the 100 - 200 KV facilities

Voter	Entity	Segment	Vote	Comment
				(defined in Attachment A) to which the standard will apply (based on Attachment B); 3) some combination of the Regional Entity and the Planning Coordinator are responsible for identifying below 100 kV facilities (defined in Attachment A) to which the standard will apply (based on Attachment B); and 4) Transmission Owners, Generator Owners, and Distribution Providers that own the facilities that have been deemed applicable are responsible for complying with the requirements of the standard. If PacifiCorp's understanding of these concepts is generally correct, they must be more clearly stated in PRC-023-2. 2. As is currently drafted, the language contained in the applicability section, Requirements R6 and R7, and Attachment B are circular, unclear, and redundant. In order for registered entities to understand their obligations, the standards must be absolutely clear on what is required and by whom. PacifiCorp suggests the following: 1) remove R6 because it is redundant with the Applicability Section 4.2 (or vice versa) and clarify the role of the Planning Coordinator and the application of Attachment B criteria; 2) Applicability Section 4.2.3 and the second bullet in Attachment B appear to contradict as Section 4.2.3 defines a role for the Planning Coordinator whereas the second bullet in Attachment B does not - this may be correct for some reason, however, the role of the Planning Coordinator and the Regional Entity in evaluating facilities below 100 kV must be more clearly defined. PacifiCorp does not have any substantive issues with the Attachment B criteria. However, in order to be enforceable, the legal obligations imposed on registered entities under PRC-023-2 must be more clearly stated.
Response: Thank you for your comment. 1. The understanding described in your first comment are correct, although the drafting team notes that Requirement R7 was removed prior to posting the standard for comments and concurrent ballot. In addition to removing Requirement R7, the drafting team made a number of clarifying modifications to the Applicability, Requirement R6, and Attachment B. 2. The commenter has made references to Requirement 7 and to an Applicability section that are not part of the standard that was posted for comment and concurrent ballot. We believe that the restructured Applicability section and clarifying modifications to Requirement R6 and Attachment B address the commenter's concerns related to clarity and circularity.				
David Thompson	Tennessee Valley Authority	5	Affirmative	For Attachment B part B1: "Permanent flowgate" is too ambiguous. Most entities in the eastern interconnect use flowgates in many different processes such as EMS systems and state estimator, transfer capability calculations, congestion management processes, and market calculations. All of these processes have

Voter	Entity	Segment	Vote	Comment
				flowgates that could be considered “permanent”. If this standard is pointing to the IDC Book of Flowgate (BOF) Permanent flowgates, then this should be so stated. However, since the IDC BOFs is not the most up to date list of flowgates, we suggest that a better line criticality identification to reliability is if a TLR has been called on the flowgate in the last two year. We recommend that instead of “permanent flowgate”, the B1 portion of Attachment B1 should say “ in the IDC Book of Flowgates and a TLR 3 or greater has been called on the flowgate in the last two years”.
Response: Thank you for your comments. The drafting team appreciates the suggestion to further refine the Flowgates of interest in the context of criterion B1. However, the drafting team believes that the Flowgates of interest must be determined based on the reliability basis for adding the Flowgate rather than historical transfers. Even if a TLR has not been called on a Flowgate for an extended period of time, during a system disturbance an overload on a monitored Facility comprising the Flowgate could lead to cascading outages if relay loadability requirements are not met. The drafting team believes it is best to continue to refer to circuits that are monitored Facilities of Flowgates that are included to address reliability concerns for loading of those circuits.				
Edward P. Cox	AEP Marketing	6	Affirmative	The wording of Attachment A, section 1.6 should be made consistent to avoid any confusion. AEP suggests that it be reworded to read: "Supervisory elements used as fault detectors associated with pilot wire or current differential protection systems where the system is capable of tripping for loss of communications".
Response: Thank you for your comment. The drafting team apologizes for confusion regarding Attachment A, Section 1.6 during the previous posting. The drafting team had intended to provide additional clarification. The drafting team has inserted parenthetical statements to clarify that the phrase “phase overcurrent supervisory elements” refers to phase fault detectors and “current-based communication-assisted schemes” refers to pilot wire, phase comparison, and line current differential schemes. We believe this modification is in-line with your recommended modification.				
Jennifer Richardson	Ameren Energy Marketing Co.	6	Negative	(1) We do not agree with the implied establishment of ratings outside of the requirements of FAC-008 in Requirement R1, criterion 1, which implies the establishment of a 4 hour rating. Rather than specifically identify the duration, the term ‘highest seasonal long-term emergency’ rating should be used. (2) Attachment B Criterion B1 still includes the consideration of flowgates. We believe that this criterion should be removed from Attachment B. (3) Attachment B Criterion B4 includes the consideration of double contingency

Voter	Entity	Segment	Vote	Comment
				events without manual system adjustments between contingencies. While the specific mention of Category C3 contingencies is removed, which would permit limiting consideration of multiple contingency events to Category C1 bus fault, C2 breaker failure, and C5 common structure outages where no operator intervention would be possible, such contingency selection would be up to the Planning Coordinator, not the individual Transmission Owner. As written, the Facility owner would only have input as to the threshold level against which the post-contingency loading would be compared, rather than the selection of the multiple contingencies to be simulated. Any 'N-1-1' contingencies should be considered as congestion issues and should not be considered as part of the criteria in Attachment B for this reliability standard.

Response: Thank you for your comments.

1. The drafting team would understand this concern if the standard required that entities establish 4-hour ratings; however, the drafting team notes that this criterion intentionally refers to "the available defined loading duration nearest 4 hours" to make it clear that an entity is not required to develop a 4-hour rating. An entity may use an existing rating, for any time duration, so long as when multiple ratings are available an entity uses their existing rating that is based on a time duration nearest to 4 hours. This phrase has remained unchanged from the "Zone 3" and "Beyond Zone 3" reviews completed following the August 14, 2003 Northeast Blackout and is part of the approved standard PRC-023-1. The drafting team is not aware of any assertion that this criterion establishes a de facto requirement for entities to develop ratings based on 4-hour duration.
2. As noted in the NERC Glossary, "Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits." This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. To the extent that Flowgates are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates.
3. The test identified in criterion B4 is consistent with, and developed specifically to address, the reliability concern driving the need for this standard. System disturbances in which relay loadability was a contributing factor, such as occurred on August 14, 2003, involve multiple contingencies without sufficient time for operator action. The drafting team notes that if manual adjustments were allowed between contingencies in criterion B4, this criterion would not identify any circuits subject to this standard except in cases where TPL-003 is violated. The test appropriately identifies circuits that may be loaded to levels that challenge relay settings when multiple contingencies occur. When such circuits are identified the Facility owner is required to meet relay loadability requirements to prevent the circuit from tripping unnecessarily before an operator has time to take corrective action. The drafting team respectfully points out that the Facility owner is not required to take any action to prevent overloads from occurring under such circumstances; the Facility owner is required only to provide relay loadability per the requirements in PRC-023 to mitigate the potential for such N-2 contingencies from leading to instability, uncontrolled separation, or cascading outages. The drafting believes that assigning selection of contingencies to the Planning Coordinator, and requiring Planning Coordinator consultation with the Facility owners regarding evaluation of post-contingency loading, is consistent with

Voter	Entity	Segment	Vote	Comment
the NERC Functional Model.				
Brenda S. Anderson	Bonneville Power Administration	6	Negative	1. BPA believes that there is a major discontinuity in the logical flow of the standard. As described in Section 4.2, the standard applies to certain transmission lines and transformers. In Requirement R1, there are thirteen criteria to select from "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". Of these thirteen criteria, only two apply to transformers--number ten and eleven. The way that these two are buried in between the other criteria that apply to line terminals and the way that they are written creates a question as to whether they apply to all transformers or only to transformers that are part of a transformer-terminated line. Additionally, since they are part of the group of thirteen criteria, of which only one must be selected, it appears that criteria ten and eleven can be ignored if another criterion is selected for a transformer-terminated line. BPA forsees this issue causing enough confusion among auditors and transmission owners that we cannot vote in favor of the standard until it is remedied. It would clear up the confusion if Criterion 10 was separated into two parts: one part that deals only with transmission line relays for transformer-terminated lines, and a second part that deals with load-responsive transformer relays. The second part--that deals with load-responsive transformer relays--should be moved along with Criterion 11 into a new requirement. This way, all of the criteria in Requirement 1 will apply only to line relays, with only one of the criteria needed to ensure that the line relays will not limit transmission system loadability. The new requirement (suggest using R2 and bumping the other requirements up a number) would deal specifically with load responsive transformer relays. Because this requirement would not be intermingled among the 13 optional criteria of Requirement 1, it would be clear that all load responsive transformer relays--not just those for transformer-terminated lines--were required to comply. 2. The drafting team has cleared up a major issue with Criterion 10.1 of Requirement 1 by clarifying that load responsive transformer relays must not expose a transformer to fault levels and durations that exceed the transformers mechanical withstand capability. This makes the requirement achievable, while the earlier version, which required that the relays not expose a transformer to fault levels and durations that exceeded its capability, was not. However, the mechanical withstand capability is not a well defined value, and the drafting

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				team's use of a footnote to clarify this requirement is not sufficient. BPA agrees with the use of IEEE C57.109-1993 as the best way to define mechanical withstand capability, but if this is to be used as the measure of this requirement, it should be written into the requirement and not merely mentioned as a footnote. In addition, Clause 4.4, Figure 4 of IEEE C57.109-1993, as mentioned in the footnote, applies only to Category IV transformers. A close look at the standard reveals that the mechanical withstand capability curves for the other categories are not the same, and the requirements for these other categories must be identified as well.
Response: Thank you for your comments. 1. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that the structure of Requirement R1 is unchanged from the approved PRC-023-1 and is consistent with the “Zone 3” and “Beyond Zone 3” reviews completed by industry following the August 14, 2003 Northeast Blackout. The drafting team provided additional clarity specific to criterion 10 by splitting the fault protection aspect directed in the order (now part 10.1) from the relay loadability aspects. The drafting team believes that combining portions of criteria 10 and 11 at this time would add confusion by intermingling fault protective relays and overload relays. However, the drafting team will include your recommendations in the issues database for future consideration in the next general revision of the standard. 2. The drafting team believes that because the reference does not establish a requirement, rather it defines the phrase mechanical withstand capability, it is most appropriately included as a footnote rather than within Requirement R1, criterion 10. The drafting team also believes that a general citing of IEEE C57.109 within the requirements would be problematic in that we are only referencing a portion of the standard. The drafting team notes that the mechanical withstand is well-defined within the standard and that a specific reference to Clause 4.4, Figure from IEEE C57.109-1993 referenced in PRC-023-2 is sufficient. Category IV transformers are defined as transformers over 10,000 kVA (10 MVA) single-phase or 30,000 kVA (30 MVA) three-phase. Since this standard applies to BES facilities, the drafting team believes that the vast majority (if not all) of the applicable transformers will be Category IV transformers; if any Category III transformers fall within the applicability of this standard, the associated mechanical characteristic is virtually identical.				
Robert Hirchak	Cleco Power LLC	6	Negative	Section 4.2 establishes the conditions to ultimately include the entire electric power infrastructure under the umbrella of protecting the "bulk electric system" which was originally defined as 200kV and above. Cleco is concerned this ever expanding regulatory umbrella is not justified.
Response: Thank you for your comment. The drafting team believes that Section 4.2 will identify only those circuits that if they trip due to relay loadability, may contribute to undesirable system performance similar to what occurred during the August 14, 2003 blackout. The criteria developed in Attachment B were developed to achieve this purpose. To the extent the commenter is concerned with the reference to facilities operated below 100 kV, the drafting team points out that consistent				

Voter	Entity	Segment	Vote	Comment
with the FERC position in Order 733-A we expect that references to circuits operated below 100 kV will have narrow applicability. The drafting team also notes that to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this the reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES."				
Mark S Travaglianti	FirstEnergy Solutions	6	Affirmative	We applaud the drafting team for their diligent and expeditious work on responding to the FERC directives of Order 733. We support the standard but ask that the team clarify the effective dates. Compliance Application Notice CAN-0013 which was recently posted for industry comment correctly adds clarification to the actual effective date for (1) Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System; (2) Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System; and (3) Switch-on-to-fault schemes on all applicable facilities. Since this CAN specifies the date of October 1, 2013 in the U.S., we ask that the following sections of PRC-023-2 be revised to include this date: "5.1.1.1.3 For switch-on-to-fault schemes as described in PRC-023-2 - Attachment A, Section 1.3, the later of the first day of the first calendar quarter after applicable regulatory approval of PRC-023-2 or the first day of the first calendar quarter 39 months following applicable regulatory (October 1, 2013 in the U.S.) approval of PRC-023-1; or in those jurisdictions where no regulatory approval is required, the later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011." and "5.1.2.1 The later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator (October 1, 2013 in the U.S.) 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."
Response: Thank you for your comments. The drafting team acknowledges the complexity involved in the effective dates for this standard. The drafting team has reformatted the Effective Dates section of the standard into a tabular format consistent with CAN-0013 and has inserted the US effective date (October 1, 2013) where appropriate.				
Thomas E Washburn	Florida Municipal Power Pool	6	Negative	The Regional Entity is not the correct entity to make decisions concerning what < 100 kV equipment is critical or not. It is too subject to inconsistent criteria being applied across the continent. It also is not in alignment with the regulatory construct of a stakeholder process described in Section 215 of the Federal Power Act which affords us the opportunity to learn from each other and develop better answers and solutions that appropriately balance costs, benefits and risks. Development of

Voter	Entity	Segment	Vote	Comment
				criteria and the application of that criteria ought to be a collaborative process continent-wide such that the criteria are applied consistently across the continent. This can be done separately, or as part of the BES definition effort currently underway. In the interim, many regions have Planning Coordinators that are not self-regulating, e.g., the Planning Coordinator is separate from the asset owners. Most of the Planning Coordinators are stakeholder organization whose "Planning Committees" would make the determination. For entities that do self-regulate, e.g., they are both the asset owner and Planning Coordinator, presumably the Regional Entity could form a stakeholder process with a Planning Committee whose members include appropriate and balanced representation from the stakeholders. These "Planning Committees" could be an alternative source for a stakeholder process to determine criteria for < 100 kV Applicability and apply that criteria while a continent-wide effort is underway to determine that criteria. These "Planning Committees" could remain in place to apply the continent-wide criteria to the regional system.
Response: Thank you for your comment. The drafting team notes that PRC-023 does not grant the Regional Entity any authority, rather it reflects language already contained in the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list entities that do not own or operate "a transmission element below 100 kV associated with <u>a facility that is included on a critical facilities list that is defined by the Regional Entity</u> (emphasis added)." However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES."				
Silvia P. Mitchell	Florida Power & Light Co.	6	Negative	Objection to including Attachment B, without additional language. Currently, there is no provision in R6 that explains to the Transmission Owner, Generation Owner or Distribution Provider their right to challenge a determination under the NERC Rules of Procedure. Likewise, under the current language, a Planning Coordinator would have no understanding that its determination could be challenged. Concurrent with this ballot, NERC is soliciting comments on its new Rules of Procedure Section 1700, which will explains the challenge process. Hence, without the additional language proposed below that cross references the Rules of Procedure, PRC-023-2 does not appear to meet certain essential attributes listed in the NERC Rules of Procedures Section 302, such as (6) completeness and (8) clear language. Thus, to address this issue, the following language should be added as a new requirement 6.6: "Pursuant to Section 1700 of the NERC Rules of Procedure, a Transmission Owner, Generator or Distribution Provider may challenge a determination (made pursuant to requirement 6 (and its subparts)) that a facility it owns, in part or whole, is subject

Voter	Entity	Segment	Vote	Comment
				to compliance with PRC-023-2."
Response: Thank you for your comment. The drafting team notes that it would not be appropriate to include a Requirement 6.6 as proposed by the commenter because the proposed language is explanatory text and does not create a compliance obligation for any entity. The drafting team also notes that the reference to Section 302 of the Rules of Procedure is not relevant to including a reference to the appeals process in Section 1700. Note that Completeness is not at issue because a reference to the appeals process is not necessary to determine the required level of performance and Clear Language is not at issue because a reference to the appeals process is not required for responsible entities, using reasonable judgment and in keeping with good utility practices, to arrive at a consistent interpretation. Finally, the drafting team notes that entities have the right to appeal a decision of the Planning Coordinator regardless of whether such explanatory text is included in PRC-023-2.				
Jessica L Klinghoffer	Kansas City Power & Light Co.	6	Negative	1. The criteria with Attachment B is not consistent with the TPL planning standards and is likely to identify transmission facilities that do not pose a reliability threat to the operation of the interconnection. The criteria in Attachment B should focus on identifying transmission facilities that play a reliability role in maintaining equipment loadings within SOL and IROL facility ratings and not include other considerations such as flowgates which are a mechanism for energy market management. 2. In addition, the implementation time frames specified are not clear whether the implementation time frame of 24 months is an extension from the 18 month time frame for the RC to identify circuits using the criteria in Attachment B or if the 24 months is concurrent with the 18 months. Also, it is uncertain whether the 24 months will be sufficient without knowing the impact of the RC analysis.
Response: Thank you for your comments. 1. The criteria identified in Attachment B are consistent with, and developed specifically to address, the reliability concern driving the need for this standard. The drafting team continues to believe that Flowgates addressing reliability concerns for loading of circuits is an appropriate inclusion in these criteria. As noted in the NERC Glossary, "Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits." This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. To the extent that Flowgates are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates. 2. The drafting team believes the commenter is referring to the time provided to a Facility owner to comply with PRC-023 after the Planning Coordinator identifies a circuit is subject to PRC-023-2 per application of Attachment B. The drafting team notes that in the previous posting of the standard this timeframe was extended from 24 months to 39 months. Specific to the commenter's question, the standard identifies the 39 months are measured from "notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to				

Voter	Entity	Segment	Vote	Comment
PRC-023-2 per application of Attachment B." The 39 months in neither concurrent with nor an extension of the 18 months provided to the Planning Coordinator.				
Daniel Prowse	Manitoba Hydro	6	Negative	Please see comments previously submitted by Manitoba Hydro regarding the effective date and the items included in Section 1.6 of Attachment A.
Response: Thank you for your comments. 1. The drafting team has considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1. Extending the timeframe included consideration of the number of circuits that may be identified by the Planning Coordinator. 2. Items included in Section 1.6 of Attachment A are included to address the concerns noted by FERC in Order 733. Settings for the protection schemes of concern are often very sensitive – well below load current – and dependent on the integrity of the communication channel to make a trip/no trip decision where other telecommunication system technologies require the operation of other protection system elements (usually distance elements) which are already subject to the requirements of this standard. Therefore, they will trip immediately due to load current upon the loss of communications, and are dependent on the fault detectors to inhibit trip which must therefore be secure regardless of how infrequently loss of communications may occur.				
Marjorie S. Parsons	Tennessee Valley Authority	6	Affirmative	For Attachment B part B1: "Permanent flowgate" is too ambiguous. Most entities in the eastern interconnect use flowgates in many different processes such as EMS systems and state estimator, transfer capability calculations, congestion management processes, and market calculations. All of these processes have flowgates that could be considered "permanent". If this standard is pointing to the IDC Book of Flowgate (BOF) Permanent flowgates, then this should be so stated. However, since the IDC BOFs is not the most up to date list of flowgates, we suggest that a better line criticality identification to reliability is if a TLR has been called on the flowgate in the last two year. We recommend that instead of "permanent flowgate", the B1 portion of Attachment B1 should say " in the IDC Book of Flowgates and a TLR 3 or greater has been called on the flowgate in the last two years".
Response: Thank you for your comments. The drafting team appreciates the suggestion to further refine the Flowgates of interest in the context of criterion B1. However, the drafting team believes that the Flowgates of interest must be determined based on the reliability basis for adding the Flowgate rather than historical transfers. Even if a TLR has not been called on a Flowgate for an extended period of time, during a system disturbance an overload on a monitored Facility comprising the Flowgate could lead to cascading outages if relay loadability requirements are not met. The drafting team believes it is best to continue to refer to circuits that are monitored Facilities of Flowgates that are included to address reliability concerns for				

Voter	Entity	Segment	Vote	Comment
loading of those circuits.				
Larry D Grimm	Texas Reliability Entity	10	Negative	1. In R1, criteria 10 and 11, the references to “operator established emergency transformer rating” should be changed to “owner established emergency transformer rating” to be consistent with R1. Note that FAC-008 and FAC-009 require the Transmission Owner and Generator Owner entities to establish Facility Ratings. 2. In R1, criteria 6, 7, 8, and 9, what is the definition of “remote to load”, “remote from generation stations”, “remote to the system”, and “remote to the bulk system”? Also, the statement in criteria 7, 8, and 9, “under any system configuration”, is extremely broad and will be difficult to plan for and enforce. 3. In R3, wording may present a possible conflict with FAC rating methodology, or should R3 be used as the FAC rating methodology in this case. What is the form of agreement required from the Planning Coordinator, Transmission Operator, and RC? 4. In R5, the TO, GO, and DP should also provide the updated list of circuits to the Transmission Planner, Planning Coordinator, and Reliability Coordinator as well as the Regional Entity. 5. Attachment A, Item 2. Consider including current differential protection systems that are designed to respond only to internal fault conditions and not overload conditions in the list of systems that are excluded from this standard. 6. Attachment B, B3. NUC-001 uses Generator Operator instead of plant owner. 7. Attachment B, B4.b. Suggest rewording as follows “For circuits operated between 100 kV and 200 kV, evaluate the post-contingency loading after contingency evaluations per TPL-003, Category A, B, and C3, 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.”
Response: Thank you for your comments. 1. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that the phrase “operator established emergency transformer rating” is unchanged from the approved PRC-023-1. The drafting team will include your recommendation in the issues database for future consideration in the next general revision of the standard. 2. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that Requirement R1, criteria 7, 8, and 9 are unchanged from the approved PRC-023-1. Additional explanation is provided in the Reference Document posted with standard PRC-023-1.				

Voter	Entity	Segment	Vote	Comment
3. When an entity uses criterion 6, 7, 8, 9, 12, or 13 as the basis for verifying transmission line relay loadability, Requirement R3 should be used as the rating methodology for the relevant circuits. Agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator can be documented by evidence such as dated correspondence as noted in Measure M3. The drafting team will request this issue be added to the Issues Database for the FAC standards at such time they are to be revised. 4. The purpose of providing the information to the Regional Entity is for the ERO to make this information available, upon request, to users, owners, and operators of the Bulk Electric System, and directed in ¶224 of Order 733. The drafting team believes the proposed change is unnecessary since the Transmission Planner, Planning Coordinator, and Reliability Coordinator can request this information from the ERO. 5. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team will include your recommendation in the issues database for future consideration in the next general revision of the standard. 6. Plant owner has been changed to Generator Operator for consistency with NUC-001 as recommended by the commenter. 7. The drafting team believes that it is unnecessary to include Category A and B contingencies in criterion B4 since the loading would not exceed the Facility Rating except in cases of non-compliance with NERC Reliability Standards TPL-001 and TPL-002. Similarly, the drafting team has previously removed the reference to Category C contingencies because it resulted in confusion with some entities because the test required in criterion B4 is not the same as Category C3. The test specified in criterion B4 does not include manual system adjustments between contingencies. The drafting team notes that if manual adjustments were allowed between contingencies in criterion B4, this criterion would not identify any circuits subject to this standard except in cases where TPL-003 is violated.				

END OF REPORT

Implementation Plan for PRC-023-2: Transmission Relay Loadability

1. Standards Involved

- PRC-023-2 —Transmission Relay Loadability

2. Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before the Transmission Relay Loadability standard can be implemented.

3. Proposed 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
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	Later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011[1]

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	Effective Date: Jurisdictions where No Regulatory Approval is Required
		of the first calendar quarter 39 months following applicable regulatory approvals of PRC-023-1 (October 1, 2013)	
	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
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	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

Requirement	Applicability	Effective Date: Jurisdictions where Regulatory Approval is Required	Effective Date: Jurisdictions where No Regulatory Approval is Required
		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	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
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

4. Applicability

4.1. Requirements within the proposed standard apply to the following:

4.1.1. Functional Entity

4.1.1.1. 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).

4.1.1.2. 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).

4.1.1.3. 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.

4.1.1.4. Planning Coordinators

4.1.2. Circuits

4.1.2.1. Circuits Subject to Requirements R1 – R5

4.1.2.1.1. Transmission lines operated at 200 kV and above

4.1.2.1.2. Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator

4.1.2.1.3. Transmission lines operated below 100 kV that are included on a critical facilities list defined by the Regional Entity[2] and selected by the Planning Coordinator in accordance with R6

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

4.1.2.1.5. Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator

4.1.2.1.6. Transformers with low voltage terminals connected below 100 kV that are included on a critical facilities list defined by the Regional Entity and selected by the Planning Coordinator

4.1.2.2. Circuits Subject to Requirement R6

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

4.1.2.2.2. Transmission lines operated below100 kV and transformers with low voltage terminals connected below 100 kV that are included on a critical facilities list defined by the Regional Entity

4.2. Other entities may be recipients of data as described in this standard, but have no requirements placed upon them

5. Implementation Dates

For circuits already identified and subject to the requirements in PRC-023-1, the existing implementation dates will remain in effect.

6. Retired Standards

Requirement R1 of PRC-023-1 is retired the first day of the first calendar quarter after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first calendar quarter after Board of Trustees adoption.

Requirement R2 of PRC-023-1 is retired the first day of the first calendar quarter after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

Requirement R3 of PRC-023-1 is retired the first day of the first calendar quarter 18 months after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 18 months after Board of Trustees adoption.

[2] If the Regional Entity has developed such a list.

When all requirements of PRC-023-2 become effective in all jurisdictions as specified above, PRC-023-1 — Transmission Relay Loadability will be retired.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan for PRC-023-2~~—~~: Transmission Relay Loadability

1. Standards Involved

- PRC-023-2 —Transmission Relay Loadability

2. Prerequisite Approvals

There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before the Transmission Relay Loadability standard can be implemented.

3. Proposed Effective Dates

~~3.1. Requirement R1~~

~~3.1.1. For transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above~~

~~3.1.1.1.~~ The ~~first day~~effective dates of the ~~first calendar quarter after applicable regulatory approvals, or~~requirements in ~~those jurisdictions where no regulatory approval is required,~~ the ~~first calendar quarter after Board of Trustees adoption, except as noted below.~~

~~3.1.1.1.1. For the addition to Requirement R1, criterion 10, to set transformer fault protection relays and transmission line 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, the first day of the first calendar quarter 12 months after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 12 months after Board of Trustees adoption.~~

~~3.1.1.1.2. For supervisory elements as described in~~ PRC-023-2 ~~– Attachment A, Section 1.6, the first day of the first calendar quarter 24 months after applicable regulatory approvals, or in those jurisdictions where regulatory approval is not required, the 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, the 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~~ standard corresponding to the applicable Functional Entities and circuits are summarized in the following ~~applicable regulatory approvals of PRC-023-1; or in those jurisdictions where no regulatory approval is required, the later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011.~~table:

~~3.1.2. For circuits identified by the Planning Coordinator pursuant to Requirement R6~~

~~3.1.2.1. The 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.~~

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~~**3.2. Requirements R2 and R3**~~

~~**3.2.1.** For transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above.~~

~~**3.2.1.1.** The first day of the first calendar quarter after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.~~

~~**3.2.2.** For circuits identified by the Planning Coordinator pursuant to Requirement R6~~

~~**3.2.2.1.** The 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.~~

~~**3.3. Requirements R4 and R5**~~

~~The first day of the first calendar quarter six months after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees adoption~~

~~**3.4. Requirement R6**~~

~~The first day of the first calendar quarter 18 months after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 18 months after Board of Trustees adoption~~

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	Later of the first day of the first calendar quarter after Board of

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Requirement	Applicability	Effective Date: Jurisdictions where Regulatory Approval is Required	Effective Date: Jurisdictions where No Regulatory Approval is Required
		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)	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 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
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	Later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a

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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
		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	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
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

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4. Applicability

4.1. Requirements within the proposed standard apply to the following:

4.1.1. Functional Entity

4.1.1.1. 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).

4.1.1.2. 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).

4.1.1.3. 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.

4.1.1.4. Planning Coordinators

4.1.2. Circuits

4.1.2.1. Circuits Subject to Requirements R1 – R5

4.1.2.1.1. Transmission lines operated at 200 kV and above

4.1.2.1.2. Transmission lines operated at 100 kV to 200 kV selected by the Planning Coordinator

4.1.2.1.3. Transmission lines operated below 100 kV that are included on a critical facilities list defined by the Regional Entity[2] and selected by the Planning Coordinator in accordance with R6

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

4.1.2.1.5. Transformers with low voltage terminals connected at 100 kV to 200 kV selected by the Planning Coordinator

4.1.2.1.6. Transformers with low voltage terminals connected below 100 kV that are included on a critical facilities list defined by the Regional Entity and selected by the Planning Coordinator

4.1.2.2. Circuits Subject to Requirement R6

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

4.1.2.2.2. Transmission lines operated below100 kV and transformers with low voltage terminals connected below 100 kV that are included on a critical facilities list defined by the Regional Entity

4.2. Other entities may be recipients of data as described in this standard, but have no requirements placed upon them

5. Implementation Dates

For circuits already identified and subject to the requirements in PRC-023-1, the existing implementation dates will remain in effect.

6. Retired Standards

Requirement R1 of PRC-023-1 is retired the first day of the first calendar quarter after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first calendar quarter after Board of Trustees adoption.

Requirement R2 of PRC-023-1 is retired the first day of the first calendar quarter after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.

[2] If the Regional Entity has developed such a list.

Requirement R3 of PRC-023-1 is retired the first day of the first calendar quarter 18 months after applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 18 months after Board of Trustees adoption.

When all requirements of PRC-023-2 become effective in all jurisdictions as specified above, PRC-023-1 — Transmission Relay Loadability will be retired.

Standard Development Roadmap

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

Development Steps Completed:

1. The Standards Committee approved the SAR for posting on August 12, 2010.
2. SAR posted for formal comment on August 19, 2010.
3. Standard posted for informal comment period on August 19, 2010.
4. Attachment B (Applicability Test) of standard posted for informal comment period on September 23, 2010.
5. Standard with applicability test posted for 45-day formal comment period with concurrent ballot during the last 10 days of the comment period on November 1, 2010.
6. Standard with applicability test posted for 20-day successive ballot period from January 24, 2011 to February 14, 2011.

Proposed Action Plan and Description of Current Draft:

This is the fourth draft of the standard developed to address the FERC directives in Order No. 733 and is posted for a 10-day recirculation ballot period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Conduct recirculation ballot of standard	February 2011- March 2011
2. Submit to NERC Board of Trustees for approval to file	March 2011
3. File standard with FERC for approval	March 2011

A. Introduction

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

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 below100 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**
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	Later of the first day of the first calendar quarter 39 months	Later of the first day of the first calendar quarter 39 months

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.

	Coordinator pursuant to Requirement R6	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	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
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
R4	Each Transmission Owner, Generator	First day of the first	First day of the first

	Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability	calendar quarter six months after applicable regulatory approvals	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

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.

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.

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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 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 per application of Attachment B, including identification of the first calendar year in which any criterion in 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 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

- 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 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. 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 than 15 months and less than 24 months lapsed between assessments. OR	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 months or more lapsed between assessments. OR	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. OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than

		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. (part 6.2)	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)	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 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	
2	November 1, 2010	Revised to address directives from Order 733	
2	January 14, 2011	Revised to address formal industry comments	
2	February 23, 2011	Revised to address successive ballot comments	

PRC-023 — 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 — 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.

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[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.

Standard Development Roadmap

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

Development Steps Completed:

1. The Standards Committee approved the SAR for posting on August 12, 2010.
2. SAR posted for formal comment on August 19, 2010.
3. Standard posted for informal comment period on August 19, 2010.
4. Attachment B (Applicability Test) of standard posted for informal comment period on September 23, 2010.
5. Standard with applicability test posted for 45-day formal comment period with concurrent ballot during the last 10 days of the comment period on November 1, 2010.
6. Standard with applicability test posted for 20-day successive ballot period from January 24, 2011 to February 14, 2011.

Proposed Action Plan and Description of Current Draft:

This is the fourth draft of the standard developed to address the FERC directives in Order No. 733 and is posted for a 10-day recirculation ballot period.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Conduct recirculation ballot of standard	February 2011- March 2011
2. Submit to NERC Board of Trustees for approval to file	March 2011
3. File standard with FERC for approval	March 2011

A. Introduction

1. **Title: Transmission Relay Loadability**

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

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 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

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 ~~included on a critical facilities list defined by~~part of the ~~Regional Entity~~~~[1]~~ BES and selected by the Planning Coordinator in accordance with R6.

FERC Order 733, ¶60: Apply an "add in" approach to sub-100 kV facilities.

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 ~~included on a critical facilities list defined by~~part of the ~~Regional Entity~~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

FERC Order 733, ¶284: Remove the exceptions footnote from the "Effective Dates" section.

~~[1] If the Regional Entity has developed such a list.~~

4.2.2.2 Transmission lines operated below100 kV and transformers with low voltage terminals connected below 100 kV that are ~~included on a critical facilities list defined by the Regional Entity~~part of the BES

5. Effective Dates

~~**5.1. Requirement R1**~~

~~**5.1.1** For transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above.~~

~~**5.1.1.1**~~ The ~~first day~~effective dates of the ~~first calendar quarter after applicable regulatory approval or~~requirements in ~~those jurisdictions where no regulatory approval is required,~~ the ~~first calendar quarter after Board of Trustees adoption, except as noted below.~~

~~**5.1.1.1.1** For the addition to Requirement R1, criterion 10, to set transformer fault protection relays and transmission line 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, the first day of the first calendar quarter 12 months after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 12 months after Board of Trustees adoption.~~

~~**5.1.1.1.2** For supervisory elements as described in~~ PRC-023-2 ~~– Attachment A, Section 1.6, the first day of the first calendar quarter 24 months after applicable regulatory approvals, or in those jurisdictions where regulatory approval is not required, the 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, the later of the first day of the first calendar quarter after applicable regulatory approval of PRC-023-2 or the first day of the first calendar quarter 39 months~~ standard corresponding to the applicable Functional Entities and circuits are summarized in the following ~~applicable regulatory approval of PRC-023-1; or in those jurisdictions where no regulatory approval is required, the later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011.~~table:

~~**5.1.2** For circuits identified by the Planning Coordinator pursuant to Requirement R6~~

~~**5.1.2.1** The 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.~~

~~**5.2. Requirements R2 and R3**~~

~~**5.2.1** For transmission lines operating at 200 kV and above and transformers with low voltage terminals connected at 200 kV and above.~~

~~**5.2.1.1** The first day of the first calendar quarter after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter after Board of Trustees adoption.~~

~~**5.2.2** For circuits identified by the Planning Coordinator pursuant to Requirement R6~~

~~**5.2.2.1** The 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.~~

~~**5.3. Requirements R4 and R5**~~

~~The first day of the first calendar quarter six months after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months after Board of Trustees adoption.~~

~~**5.4. Requirement R6**~~

~~The first day of the first calendar quarter 18 months after applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter 18 months after Board of Trustees adoption.~~

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	Later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011[2]

2 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.

			following applicable regulatory approvals of PRC-023-1 (October 1, 2013)	
		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
		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
	R2 and R3	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	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

		list before the applicable effective date	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
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

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[3] 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.

[3] 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:

FERC Order 733, ¶203: Modify sub-requirement R1.10 to verify equipment is capable of sustaining the anticipated overload associated with the fault.

- 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[4].

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[5].

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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[4] 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

[5] IEEE standard C57.~~115, Table 3, specifies~~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]*

FERC Order 733, ¶244: Include section 2 of Appendix A as an additional Requirement.

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]*

FERC Order 733, ¶186: Modify R1.2 to require that TOs, GOs, and DPs give their TOPs a list of transmission facilities that implement R1.2.

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]*

FERC Order 733, ¶224: Make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant sub-requirement R1.12.of anticipated overload.

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 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 per application of Attachment B, including identification of the first calendar year in which any criterion in 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 ~~or~~, 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 ~~or~~, 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 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

- 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 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. 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 than 15 months and less than 24 months lapsed between assessments. OR	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 months or more lapsed between assessments. OR	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. OR The Planning Coordinator used the criteria established within Attachment B, at least once each calendar year, with no more than

		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. (part 6.2)	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)	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 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, ~~January 9, 2007~~June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com~~/~filez/reports.html~~/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf ~~.~~

   .

Field Code Changed

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	~~November 1, 2010~~TBD	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)
~~2~~	~~January 14, 2011~~	~~Revised to address formal industry comments~~	

PRC-023 — 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.** ~~Supervisory~~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.

FERC Order 733, ¶264: Revise section 1 of Attachment A to include supervising relay elements.

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 — Attachment B

FERC Order 733, ¶69: Specify the test that PCs must use to determine whether sub-200 kV facility is critical to reliability of the BES

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.
- ~~Lines~~Transmission lines operated ~~below100~~below 100 kV and transformers with low voltage terminals connected below 100 kV that are ~~included on a critical facilities list defined by~~part of the ~~Regional Entity~~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 ~~plant owner~~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[6] 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.

[6] 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-~~1~~2
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 with load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to ~~facilities~~circuits defined ~~below:~~ 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

4.2. Circuits

4.2.1 Circuits Subject to Requirements R1 – R5

~~4.1.1.1~~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 ~~as designated~~selected by the Planning Coordinator ~~as critical to the reliability~~in accordance with R6.

~~4.1.1.2~~4.2.1.3 Transmission lines operated below 100 kV that are part of the ~~Bulk Electric System.~~BES and selected by the Planning Coordinator in accordance with R6.

FERC Order 733, ¶60: Apply an "add in" approach to sub-100 kV facilities.

~~4.1.1.3~~4.2.1.4 Transformers with low voltage terminals connected at 200 kV and above.

~~4.1.1.4~~4.2.1.5 Transformers with low voltage terminals connected at 100 kV to 200 kV ~~as designated~~selected by the Planning Coordinator ~~as critical to the reliability of the Bulk Electric System~~in accordance with R6.

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

~~**4.3.** Distribution Providers with load-responsive phase protection systems as described in Attachment A, applied according to facilities defined in 4.1.1 through 4.1.4., provided~~low voltage terminals connected below 100 kV that ~~those facilities have bi-directional flow capabilities.~~

~~**4.4.** Planning Coordinators.~~

FERC Order 733, ¶284: Remove the exceptions footnote from the "Effective Dates" section.

~~5. Effective Dates[1]:~~

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

~~5.1.1 For circuits described in 4.1.1 and 4.1.3 above (except for switch-on-to-fault schemes) — the beginning~~are part of the ~~first calendar quarter following applicable regulatory approvals.~~

~~5.1.2 For circuits described in 4.1.2 and 4.1.4 above (including switch-on-to-fault schemes) — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals.~~

~~5.1.2.1~~4.2.1.6 ~~Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified~~BES and selected by ~~its~~the Planning Coordinator ~~pursuant to R3.3 to comply with R1 (including all sub-requirements) for each facility that is added to the Planning Coordinator's critical facilities list determined pursuant to R3.1~~in accordance with R6.

4.2.2 Circuits Subject to Requirement ~~3: 18 months~~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 below100 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 ~~applicable regulatory approvals.~~table:

Requirement	Applicability	Effective Date: Jurisdictions where Regulatory Approval is Required	Effective Date: 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	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

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

	transformer to fault level and duration that exceeds its mechanical withstand capability		
	• 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[2]
	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
R2 and R3	Each Transmission Owner, Generator	First day of the first	First day of the first

2 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.

	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	calendar quarter after applicable regulatory approvals	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
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

B. Requirements

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall use any one of the following criteria (Requirement R1~~.~~, criteria 1 through ~~R1.~~13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the ~~Bulk Electric System~~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] [~~Mitigation~~ 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[3] 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 ~~R1.~~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.

[3] 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 ~~they~~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~~.~~

FERC Order 733, ¶203: Modify sub-requirement R1.10 to verify equipment is capable of sustaining the anticipated overload associated with the fault.

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[4].

11. For transformer overload protection relays that do not comply with ~~R1.~~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~~. The protection must allow this overload~~, for at least 15 minutes to ~~allow~~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~~. The setting should be~~ set no less than 100° C for the top oil ~~or~~temperature or no less than 140° C for the winding hot spot temperature[5].

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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[4] 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

[5] IEEE standard C57.~~115, Table 3, specifies~~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~~.2~~ 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. ~~The~~Each Transmission Owner, Generator Owner, ~~or~~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]*

FERC Order 733, ¶244: Include section 2 of Appendix A as an additional Requirement.

~~**R2.**~~**R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that uses a circuit capability with the practical limitations described in ~~R1.~~Requirement R1, criterion 6, ~~R1.~~7, ~~R1.~~8, ~~R1.~~9, ~~R1.~~12, or ~~R1.~~13 shall use the calculated circuit capability as the Facility Rating of the circuit and shall obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator with the calculated circuit capability. *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]*

FERC Order 733, ¶186: Modify R1.2 to require that TOs, GOs, and DPs give their TOPs a list of transmission facilities that implement R1.2.

~~**R3.**~~**R4.** ~~The Planning Coordinator shall determine which of the facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV) in its Planning Coordinator Area are critical to the reliability of the Bulk Electric System to identify the facilities from 100 kV to 200 kV~~Each Transmission Owner, Generator Owner, and Distribution Provider that ~~must meet~~chooses to use Requirement ~~1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission~~ 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: ~~Medium~~Lower] [Time Horizon: Long Term Planning]*

R5. ~~The~~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]*

FERC Order 733, ¶224: Make available for review to users, owners and operators of the Bulk-Power System, by request, a list of those facilities that have protective relays set pursuant sub-requirement R1.12.of anticipated overload.

~~**1.1**~~ Each Planning Coordinator shall ~~have a process~~conduct an assessment at least once each calendar year, with no more than 15 months between assessments, by applying the criteria in Attachment B to determine the ~~facilities that are critical to the reliability of the Bulk Electric System.~~

~~**1.3.1** This process shall consider input from adjoining Planning Coordinators and affected Reliability Coordinators.~~

~~1.2~~ ~~The~~circuits in its Planning Coordinator ~~shall maintain a current list of facilities determined according to the process described in R3.1.~~

R6. ~~The~~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* ~~Coordinator shall provide a list of facilities to its~~*]*

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

~~6.3~~6.2 Provide the list of circuits to all Regional Entities, Reliability Coordinators, Transmission Owners, Generator Owners, and Distribution Providers within ~~30~~its Planning Coordinator area within 30 calendar days of the establishment of the initial list and within 30 calendar days of any changes to ~~the~~that list.

C. Measures

M1. ~~The~~Each Transmission Owner, Generator Owner, and Distribution Provider shall ~~each~~ have evidence such as spreadsheets or summaries of calculations to show that each of its transmission relays ~~are~~is set according to one of the criteria in ~~R1.~~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~~.13. ()~~)

~~M1.~~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)

~~M2.~~M3. ~~The~~Each Transmission Owner, Generator Owner, and Distribution Provider with transmission relays set according to ~~the criteria in~~Requirement R1~~.~~, criterion 6, ~~R1.~~7, ~~R1.~~8, ~~R1.~~9, ~~R1.~~12, or ~~R.~~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. (~~R2~~R3)

M4. ~~The~~ 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 ~~shall have~~, 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 ~~documented process for the determination of facilities as described in R3~~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)

~~M3.~~M6. Each Planning Coordinator shall have evidence such as power flow results, calculation summaries, or study reports that it 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 as described in Requirement R6. The Planning Coordinator shall have a ~~current~~dated list of such ~~facilities~~circuits and shall have evidence such as dated correspondence that it provided the list to the ~~approriate~~Regional Entities, Reliability Coordinators, Transmission ~~Operators~~Owners, Generator ~~Operators~~Owners, and Distribution Providers~~. (R3)~~ within its Planning Coordinator area within the required timeframe.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

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

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

~~One calendar year.~~

- For functional entities that work for their Regional Entity, the ERO shall serve as the Compliance Enforcement Authority.

~~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 ~~R3~~R6. The Planning Coordinator shall retain the most recent list of ~~facilities that are critical to~~ circuits in its Planning Coordinator area for which applicable entities must comply with the ~~reliability of the electric system~~standard, as determined per ~~R3~~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 shall ~~retain its compliance documentation for three years~~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

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

None.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	N/A	N/A	N/A	~~A Transmission Owner, Generator Owner, or Distribution Provider~~The responsible entity did not use any one of the following criteria (Requirement R1~~.~~ criterion 1 through ~~R1.~~13) for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the Bulk Electric System for all fault conditions. OR ~~A Transmission Owner, Generator Owner, or Distribution Provider~~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

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				conditions used to verify transmission line relay loadability per Requirement R1.
~~R2~~R3	N/A	N/A	N/A	~~A Transmission Owner, Generator Owner, or Distribution Provider~~The responsible entity that uses a circuit capability with the practical limitations described in Requirement R1~~.~~ criterion 6, ~~R1.~~7, ~~R1.~~8, ~~R1.~~9, ~~R1.~~12, or ~~R1.~~13 did not use the calculated circuit capability as the 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.

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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.
~~R3~~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 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	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 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)	The Planning Coordinator ~~did not~~ failed to use the criteria established within Attachment B to determine ~~which of~~ the ~~facilities (transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV)~~ circuits in its Planning Coordinator ~~Area are critical to the reliability of the Bulk Electric System~~ area for which applicable entities must comply with the standard. OR The Planning Coordinator used the criteria established within Attachment B, at least once each

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		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. (part 6.2)		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. ~~Coordinator did not identify the facilities from 100 kV to 200 kV that must meet Requirement 1 to prevent potential cascade tripping that may occur when protective relay settings limit transmission loadability.~~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)

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				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 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.

Field Code Changed

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, ~~January 9, 2007~~June 2008, prepared by the System Protection and Control Task Force of the NERC Planning Committee, available at: http://www.nerc.com~~/~filez/reports.html~~/fileUploads/File/Standards/Relay_Loadability_Reference_Doc_Clean_Final_2008July3.pdf ~~.~~

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Field Code Changed

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	TBD	Revised to address initial set of directives from Order 733	Revision (Project 2010-13)

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PRC-023 — Attachment A

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

1.1. Phase distance.

1.2. Out-of-step tripping.

1.3. Switch-on-to-fault.

1.4. Overcurrent relays.

1.5. Communications aided protection schemes including but not limited to:

1.5.1 Permissive overreach transfer trip (POTT).

1.5.2 Permissive under-reach transfer trip (PUTT).

1.5.3 Directional comparison blocking (DCB).

1.5.4 Directional comparison unblocking (DCUB).

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

FERC Order 733, ¶264: Revise section 1 of Attachment A to include supervising relay elements.

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.

~~3.~~2. The following protection systems are excluded from requirements of this standard:

~~3.1.~~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

~~3.2.~~2.2. Protection systems intended for the detection of ground fault conditions.

~~3.3.~~2.3. Protection systems intended for protection during stable power swings.

~~3.4.~~2.4. Generator protection relays that are susceptible to load.

~~3.5.~~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.

~~3.6.~~2.6. Protection systems that are designed only to respond in time periods which allow ~~operators~~ 15 minutes or greater to respond to overload conditions.

~~3.7.~~2.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings.

~~3.8.~~2.8. Relay elements associated with ~~DC~~dc lines.

~~3.9.~~2.9. Relay elements associated with ~~DC~~dc converter transformers.

PRC-023 — Attachment B

FERC Order 733, ¶69: Specify the test that PCs must use to determine whether sub-200 kV facility is critical to reliability of the BES

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[6] 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.

[6] 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.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Recirculation Ballot Window Open
Project 2010-13 – Relay Loadability Order 733
February 24-March 6, 2011

Now available at: https://standards.nerc.net/CurrentBallots.aspx

Project 2010-13 – Relay Loadability Order 733
A recirculation ballot for PRC-023-2 – Transmission Relay Loadability is open **until 8 p.m. (Eastern) on March 6, 2011.**

Instructions
Members of the ballot pool associated with this project may log in and submit their votes from the following page: https://standards.nerc.net/CurrentBallots.aspx

In the recirculation ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their prior votes. A ballot pool member who failed to cast a ballot during the last ballot window may cast a ballot in the recirculation ballot window. If a ballot pool member does not participate in the recirculation ballot, that member's last vote cast in the successive ballot that ended on February 14, 2011 will be carried over and used to determine if there are sufficient affirmative votes for this standard to pass.

This is an extremely important ballot as NERC is responding to a set of FERC directives that require submitting modifications to PRC-023-1 by March 18, 2011. We encourage all members of the ballot pool to review the revised standard and the drafting team's consideration of the comments submitted with the last ballot. The team made the following changes following the initial ballot, in support of stakeholder comments:

- Modified the applicability to clarify that the transmission lines and transformers that must have protection compliant with the standard are limited to those that are part of the BES and are selected by the Planning Coordinator. (Previously the applicability did not include the phrase "part of the BES.")
- Reformatted the presentation of the effective dates so that the dates are easier to comprehend
- Corrected footnote 5
- Revised M4 and M5 to clarify that attestations are acceptable forms of evidence
- Added another Severe VSL for R6 to cover the situation where an entity is totally noncompliant with the requirement
- Changed "supervisory elements" to "Phase overcurrent supervisory elements" for clarity in Attachment A

The drafting team will be holding a webinar to review the modifications made to the standard on Wednesday, March 2 from 1-2 pm (Eastern). The Standards Committee encourages all ballot body members to participate in this webinar.

Next Steps

Voting results will be posted and announced after the ballot window closes. This standard is scheduled to be submitted to the Board of Trustees on March 10, 2011, and filed for regulatory approval by March 18, 2011.

Project Background

When FERC issued Order 733, approving PRC-023-1 —Transmission Relay Loadability, it directed several changes to that standard and also directed development of one or more new standards within specified time periods. NERC filed for clarification and rehearing asking for clarity and an extension of time to address the directives; and the extension was granted but only applies to one of the directives. NERC is still required to file a revised standard that addresses several directives from Order 733 by March 18, 2011.

The SAR for Project 2010-13 subdivides the standard-development-related directives into three phases. Phase I addresses the specific directives from Order 733 that identified required modifications to various elements within PRC-023-1. Phase II addresses directives associated with development of a new standard to address generator relay loadabilty. Phase III addresses directives associated with writing requirements to address protective relay operations due to power swings.

Further details are available on the project page:
http://www.nerc.com/filez/standards/SAR_Project%202010-13_Order%20733%20Relay%20Modifiations.html

For more information or assistance, please contact Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 404-446-2560.

North American Electric Reliability Corporation
116-390 Village Blvd.
Princeton, NJ 08540
609.452.8060 | www.nerc.com

Ballot Results	
Ballot Name:	2010-13 Relay Loadability Order Successive Ballot_rc
Ballot Period:	2/24/2011 - 3/7/2011
Ballot Type:	recirculation
Total # Votes:	283
Total Ballot Pool:	324
Quorum:	87.35 % The Quorum has been reached
Weighted Segment Vote:	68.83 %
Ballot Results:	The Standard has Passed

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Abstain # Votes	No Vote
1 - Segment 1.	97	1	59	0.728	22	0.272	9	7
2 - Segment 2.	11	1	6	0.6	4	0.4	0	1
3 - Segment 3.	72	1	41	0.695	18	0.305	5	8
4 - Segment 4.	21	1	15	0.882	2	0.118	3	1
5 - Segment 5.	67	1	26	0.619	16	0.381	9	16
6 - Segment 6.	38	1	19	0.594	13	0.406	1	5
7 - Segment 7.	0	0	0	0	0	0	0	0
8 - Segment 8.	7	0.4	1	0.1	3	0.3	2	1
9 - Segment 9.	5	0.2	2	0.2	0	0	2	1
10 - Segment 10.	6	0.4	4	0.4	0	0	1	1
Totals	**324**	**7**	**173**	**4.818**	**78**	**2.182**	**32**	**41**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	Comments
1	Allegheny Power	Rodney Phillips	Affirmative	
1	Ameren Services	Kirit S. Shah	Negative	View
1	American Electric Power	Paul B. Johnson	Affirmative	View
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	View
1	APS	Barbara McMinn		
1	Arizona Public Service Co.	Robert D Smith	Affirmative	
1	Associated Electric Cooperative, Inc.	John Bussman	Affirmative	
1	Avista Corp.	Scott Kinney	Affirmative	

1	BC Transmission Corporation	Gordon Rawlings	Affirmative	
1	Beaches Energy Services	Joseph S. Stonecipher	Negative	View
1	Black Hills Corp	Eric Egge		
1	Bonneville Power Administration	Donald S. Watkins	Negative	View
1	CenterPoint Energy	Paul Rocha	Negative	View
1	Central Maine Power Company	Kevin L Howes	Affirmative	
1	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Chang G Choi	Affirmative	
1	City of Vero Beach	Randall McCamish	Affirmative	
1	City Utilities of Springfield, Missouri	Jeff Knottek	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Power LLC	Danny McDaniel	Negative	View
1	Colorado Springs Utilities	Paul Morland	Affirmative	
1	Commonwealth Edison Co.	Gregory Campbell		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Negative	View
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dayton Power & Light Co.	Hertzel Shamash	Affirmative	
1	Dominion Virginia Power	Michael S Crowley	Negative	View
1	Duke Energy Carolina	Douglas E. Hils	Affirmative	
1	East Kentucky Power Coop.	George S. Carruba	Affirmative	
1	Empire District Electric Co.	Ralph Frederick Meyer	Affirmative	
1	Entergy Corporation	George R. Bartlett	Affirmative	
1	FirstEnergy Energy Delivery	Robert Martinko	Affirmative	View
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Negative	
1	Gainesville Regional Utilities	Luther E. Fair	Negative	View
1	Georgia Transmission Corporation	Harold Taylor, II	Affirmative	
1	Great River Energy	Gordon Pietsch	Negative	View
1	Hoosier Energy Rural Electric Cooperative, Inc.	Robert Solomon	Affirmative	
1	Hydro One Networks, Inc.	Ajay Garg	Abstain	View
1	Idaho Power Company	Ronald D. Schellberg	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Affirmative	
1	Kansas City Power & Light Co.	Michael Gammon	Negative	View
1	Keys Energy Services	Stan T. Rzad	Affirmative	
1	Lake Worth Utilities	Walt Gill	Abstain	
1	Lakeland Electric	Larry E Watt	Affirmative	
1	Lee County Electric Cooperative	John W Delucca	Abstain	
1	Lincoln Electric System	Doug Bantam		
1	Long Island Power Authority	Robert Ganley	Affirmative	
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	Manitoba Hydro	Joe D Petaski	Negative	View
1	MidAmerican Energy Co.	Terry Harbour	Negative	View
1	Minnkota Power Coop. Inc.	Richard Burt	Negative	View
1	National Grid	Saurabh Saksena	Affirmative	View
1	Nebraska Public Power District	Richard L. Koch	Abstain	
1	New Brunswick Power Transmission Corporation	Randy MacDonald	Affirmative	
1	New York Power Authority	Arnold J. Schuff	Affirmative	
1	Northeast Utilities	David H. Boguslawski	Affirmative	
1	Northern Indiana Public Service Co.	Kevin M Largura	Affirmative	
1	NorthWestern Energy	John Canavan	Abstain	
1	Ohio Valley Electric Corp.	Robert Mattey	Affirmative	
1	Omaha Public Power District	Douglas G Peterchuck	Affirmative	
1	Oncor Electric Delivery	Michael T. Quinn	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Pacific Gas and Electric Company	Chifong L. Thomas		
1	PacifiCorp	Colt Norrish	Negative	
1	PECO Energy	Ronald Schloendorn	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	Frank F. Afranji	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Affirmative	
1	PowerSouth Energy Cooperative	Larry D. Avery	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Affirmative	
1	Public Service Company of New Mexico	Laurie Williams	Abstain	
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Affirmative	
1	Puget Sound Energy, Inc.	Catherine Koch	Negative	View
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	Santee Cooper	Terry L. Blackwell	Negative	
1	SCE&G	Henry Delk, Jr.	Abstain	
1	Seattle City Light	Pawel Krupa	Negative	View
1	Sierra Pacific Power Co.	Rich Salgo	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Texas Electric Cooperative	Richard McLeon	Abstain	
1	Southern California Edison Co.	Dana Cabbell	Negative	View
1	Southern Company Services, Inc.	Horace Stephen Williamson		
1	Southern Illinois Power Coop.	William G. Hutchison	Negative	
1	Southwest Transmission Cooperative, Inc.	James L. Jones	Affirmative	
1	Southwestern Power Administration	Gary W Cox	Affirmative	
1	Sunflower Electric Power Corporation	Noman Lee Williams	Affirmative	
1	Tampa Electric Co.	Beth Young	Negative	
1	Tennessee Valley Authority	Larry Akens	Affirmative	View
1	Texas Municipal Power Agency	Frank J. Owens	Abstain	
1	Transmission Agency of Northern California	James W. Beck	Affirmative	
1	Tri-State G & T Association, Inc.	Keith V Carman	Negative	View
1	Tucson Electric Power Co.	John Tolo		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Affirmative	
1	Western Area Power Administration	Brandy A Dunn	Affirmative	
1	Western Farmers Electric Coop.	Forrest Brock	Affirmative	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	View
2	Alberta Electric System Operator	Mark B Thompson	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Affirmative	
2	California ISO	Gregory Van Pelt	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Chuck B Manning	Negative	View
2	Independent Electricity System Operator	Kim Warren	Affirmative	View
2	ISO New England, Inc.	Kathleen Goodman	Negative	View
2	Midwest ISO, Inc.	Jason L Marshall	Negative	View
2	New Brunswick System Operator	Alden Briggs	Affirmative	
2	New York Independent System Operator	Gregory Campoli		
2	PJM Interconnection, L.L.C.	Tom Bowe	Affirmative	
2	Southwest Power Pool	Charles H Yeung	Negative	View
3	Alabama Power Company	Richard J. Mandes	Affirmative	
3	Allegheny Power	Bob Reeping	Affirmative	
3	Ameren Services	Mark Peters	Negative	
3	American Electric Power	Raj Rana		
3	Anaheim Public Utilities Dept.	Kelly Nguyen	Abstain	
3	APS	Steven Norris	Affirmative	
3	Arkansas Electric Cooperative Corporation	Philip Huff	Abstain	
3	Atlantic City Electric Company	James V. Petrella	Affirmative	
3	Avista Corp.	Robert Lafferty	Affirmative	
3	BC Hydro and Power Authority	Pat G. Harrington	Affirmative	
3	Blue Ridge Power Agency	Duane S Dahlquist		
3	Bonneville Power Administration	Rebecca Berdahl	Negative	View
3	Central Lincoln PUD	Steve Alexanderson	Affirmative	
3	City of Farmington	Linda R. Jacobson	Affirmative	
3	City of Green Cove Springs	Gregg R Griffin	Affirmative	
3	City of Leesburg	Phil Janik	Negative	
3	Cleco Corporation	Michelle A Corley	Negative	View
3	ComEd	Bruce Krawczyk	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Negative	View
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Affirmative	
3	Detroit Edison Company	Kent Kujala	Affirmative	
3	Dominion Resources Services	Michael F Gildea	Negative	View
3	Duke Energy Carolina	Henry Ernst-Jr	Affirmative	View
3	East Kentucky Power Coop.	Sally Witt	Affirmative	
3	Entergy	Joel T Plessinger	Affirmative	
3	FirstEnergy Solutions	Kevin Querry	Affirmative	View
3	Florida Municipal Power Agency	Joe McKinney		
3	Florida Power Corporation	Lee Schuster	Negative	View
3	Georgia Power Company	Anthony L Wilson	Affirmative	

3	Georgia System Operations Corporation	R Scott S. Barfield-McGinnis	Affirmative	
3	Great River Energy	Sam Kokkinen	Negative	
3	Hydro One Networks, Inc.	David L Kiguel	Abstain	View
3	JEA	Garry Baker	Affirmative	
3	Kansas City Power & Light Co.	Charles Locke	Negative	View
3	Kissimmee Utility Authority	Gregory David Woessner	Affirmative	
3	Lakeland Electric	Mace Hunter	Affirmative	
3	Lincoln Electric System	Bruce Merrill	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Affirmative	
3	Manitoba Hydro	Greg C. Parent	Negative	View
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	View
3	Mississippi Power	Don Horsley	Affirmative	
3	Muscatine Power & Water	John S Bos	Affirmative	View
3	Nebraska Public Power District	Tony Eddleman	Affirmative	
3	New York Power Authority	Marilyn Brown	Affirmative	
3	Niagara Mohawk (National Grid Company)	Michael Schiavone	Affirmative	View
3	Northern Indiana Public Service Co.	William SeDoris	Affirmative	
3	Orange and Rockland Utilities, Inc.	David Burke	Negative	
3	Orlando Utilities Commission	Ballard Keith Mutters	Affirmative	
3	PacifiCorp	John Apperson	Negative	View
3	PECO Energy an Exelon Co.	Vincent J. Catania		
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	PNM Resources	Michael Mertz		
3	Potomac Electric Power Co.	Robert Reuter	Affirmative	
3	Progress Energy Carolinas	Sam Waters	Negative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Affirmative	
3	Public Utility District No. 1 of Chelan County	Kenneth R. Johnson	Abstain	
3	Public Utility District No. 2 of Grant County	Greg Lange	Affirmative	
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	San Diego Gas & Electric	Scott Peterson		
3	Santee Cooper	Zack Dusenbury	Negative	
3	Seattle City Light	Dana Wheelock	Negative	View
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C. Young		
3	Southern California Edison Co.	David Schiada	Negative	
3	Tacoma Public Utilities	Travis Metcalfe	Affirmative	
3	Tampa Electric Co.	Ronald L Donahey	Negative	View
3	Tennessee Valley Authority	Ian S Grant	Affirmative	View
3	Tri-State G & T Association, Inc.	Janelle Marriott		
3	Wisconsin Electric Power Marketing	James R. Keller	Abstain	
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Abstain	
4	American Public Power Association	Allen Mosher	Affirmative	
4	Arkansas Electric Cooperative Corporation	Ronnie Frizzell	Abstain	
4	Central Lincoln PUD	Shamus J Gamache	Affirmative	View
4	City of New Smyrna Beach Utilities Commission	Timothy Beyrle	Affirmative	
4	Consumers Energy	David Frank Ronk	Negative	View
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	Detroit Edison Company	Daniel Herring	Affirmative	
4	Florida Municipal Power Agency	Frank Gaffney	Affirmative	
4	Fort Pierce Utilities Authority	Thomas W. Richards	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	View
4	Ohio Edison Company	Douglas Hohlbaugh	Affirmative	View
4	Public Utility District No. 1 of Douglas County	Henry E. LuBean	Affirmative	
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	Negative	View
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Tallahassee Electric	Allan Morales	Affirmative	
4	Wisconsin Energy Corp.	Anthony Jankowski	Abstain	
5		Edwin B Cano		
5	AEP Service Corp.	Brock Ondayko	Affirmative	View

5	Amerenue	Sam Dwyer	Negative	
5	Arizona Public Service Co.	Edward Cambridge	Affirmative	
5	Avista Corp.	Edward F. Groce	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Negative	View
5	City and County of San Francisco	Daniel Mason	Abstain	
5	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Max Emrick	Affirmative	
5	City of Tallahassee	Alan Gale	Abstain	
5	Cleco Power	Stephanie Huffman		
5	Consolidated Edison Co. of New York	Wilket (Jack) Ng	Negative	View
5	Consumers Energy	James B Lewis	Negative	View
5	Covanta Energy	Samuel Cabassa	Abstain	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Detroit Edison Company	Christy Wicke	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Negative	View
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	East Kentucky Power Coop.	Stephen Ricker	Affirmative	
5	El Paso Electric Company	Alfred W Morgan		
5	Electric Power Supply Association	John R Cashin		
5	Energy Northwest - Columbia Generating Station	Doug Ramey		
5	Entergy Corporation	Stanley M Jaskot	Affirmative	
5	Exelon Nuclear	Michael Korchynsky	Affirmative	
5	Florida Municipal Power Agency	David Schumann		
5	Great River Energy	Cynthia E Sulzer		
5	Green Country Energy	Greg Froehling	Affirmative	
5	Indeck Energy Services, Inc.	Rex A Roehl	Negative	View
5	Kansas City Power & Light Co.	Scott Heidtbrink	Negative	View
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	Thomas J Trickey		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Louisville Gas and Electric Co.	Charlie Martin		
5	Luminant Generation Company LLC	Mike Laney	Abstain	
5	Manitoba Hydro	S N Fernando	Negative	View
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MidAmerican Energy Co.	Christopher Schneider	Negative	View
5	Nebraska Public Power District	Don Schmit	Affirmative	
5	New Harquahala Generating Co. LLC	Nicholas Q Hayes		
5	New York Power Authority	Gerald Mannarino	Affirmative	
5	Northern California Power Agency	Tracy R Bibb		
5	Northern Indiana Public Service Co.	Michael K Wilkerson		
5	Occidental Chemical	Michelle DAntuono	Negative	View
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Orlando Utilities Commission	Richard Kinas		
5	Pacific Gas and Electric Company	Richard J. Padilla		
5	PacifiCorp	Sandra L. Shaffer	Negative	View
5	Platte River Power Authority	Pete Ungerman	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Affirmative	
5	Progress Energy Carolinas	Wayne Lewis	Negative	
5	Public Service Enterprise Group Incorporated	Dominick Grasso	Affirmative	
5	Public Utility District No. 1 of Lewis County	Steven Grega	Negative	View
5	Sacramento Municipal Utility District	Bethany Hunter	Affirmative	
5	Salt River Project	Glen Reeves	Affirmative	
5	Santee Cooper	Lewis P Pierce	Negative	
5	Seattle City Light	Michael J. Haynes	Negative	View
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Richard Jones		
5	Southern Company Generation	William D Shultz	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Negative	
5	Tenaska, Inc.	Scott M. Helyer	Abstain	
5	Tennessee Valley Authority	David Thompson	Affirmative	View
5	U.S. Army Corps of Engineers	Melissa Kurtz	Affirmative	
5	U.S. Bureau of Reclamation	Martin Bauer P.E.		
5	Wisconsin Electric Power Co.	Linda Horn	Abstain	
5	Wisconsin Public Service Corp.	Leonard Rentmeester	Abstain	
5	Xcel Energy, Inc.	Liam Noailles	Affirmative	View

6	AEP Marketing	Edward P. Cox	Affirmative	View
6	Ameren Energy Marketing Co.	Jennifer Richardson	Negative	View
6	Arizona Public Service Co.	Justin Thompson	Affirmative	
6	Bonneville Power Administration	Brenda S. Anderson	Negative	View
6	Cleco Power LLC	Robert Hirchak	Negative	View
6	Consolidated Edison Co. of New York	Nickesha P Carrol	Negative	View
6	Constellation Energy Commodities Group	Brenda Powell	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Negative	View
6	Duke Energy Carolina	Walter Yeager	Affirmative	
6	Entergy Services, Inc.	Terri F Benoit	Affirmative	View
6	Exelon Power Team	Pulin Shah	Affirmative	
6	FirstEnergy Solutions	Mark S Travaglianti	Affirmative	View
6	Florida Municipal Power Agency	Richard L. Montgomery		
6	Florida Municipal Power Pool	Thomas E Washburn	Affirmative	
6	Florida Power & Light Co.	Silvia P. Mitchell	Negative	View
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	View
6	Lakeland Electric	Paul Shipps	Negative	View
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Manitoba Hydro	Daniel Prowse	Negative	View
6	New York Power Authority	William Palazzo	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Omaha Public Power District	David Ried	Affirmative	
6	PacifiCorp	Scott L Smith	Negative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	PPL EnergyPlus LLC	Mark A Heimbach	Affirmative	
6	Progress Energy	John T Sturgeon	Negative	View
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Affirmative	
6	Public Utility District No. 1 of Chelan County	Hugh A. Owen		
6	RRI Energy	Trent Carlson		
6	Sacramento Municipal Utility District	Claire Warshaw	Affirmative	
6	Salt River Project	Mike Hummel		
6	Santee Cooper	Suzanne Ritter	Negative	
6	Seattle City Light	Dennis Sismaet	Negative	View
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tennessee Valley Authority	Marjorie S. Parsons	Affirmative	View
6	Western Area Power Administration - UGP Marketing	John Stonebarger		
6	Xcel Energy, Inc.	David F. Lemmons	Affirmative	View
8		James A Maenner	Abstain	
8		Roger C Zaklukiewicz	Negative	
8		Edward C Stein	Affirmative	
8	INTELLIBIND	Kevin Conway		
8	JDRJC Associates	Jim D. Cyrulewski	Negative	
8	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
8	Volkmann Consulting, Inc.	Terry Volkmann	Negative	
9	California Energy Commission	William Mitchell Chamberlain		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald E. Nelson	Affirmative	
9	Oregon Public Utility Commission	Jerome Murray	Abstain	
9	Snohomish County PUD No. 1	William Moojen	Abstain	
9	Utah Public Service Commission	Ric Campbell	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council, Inc.	Guy V. Zito	Abstain	View
10	ReliabilityFirst Corporation	Anthony E Jablonski	Affirmative	View
10	SERC Reliability Corporation	Carter B. Edge	Affirmative	
10	Southwest Power Pool Regional Entity	Stacy Dochoda		
10	Texas Reliability Entity	Larry D. Grimm	Affirmative	View

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Standards Announcement
Project 2010-13 – Relay Loadability Order
Recirculation Ballot Results

Now available at: https://standards.nerc.net/Ballots.aspx

Ballot Results for Revisions to PRC-023
A recirculation ballot on revisions to PRC-023 Transmission Relay Loadability concluded on March 7, 2011. The revised standard, PRC-023-2, was approved by the ballot pool.

Voting statistics are listed below, and the Ballot Results Web page provides a link to the detailed results:

Quorum: 87.35%
Approval: 68.83%

Next Steps
PRC-023-2 will be presented to the NERC Board of Trustees for adoption and filed with regulatory authorities.

Background:
As the ERO, NERC must address all directives in Orders issued by FERC. On March 18, 2010 FERC issued Order No. 733 which approved Reliability Standard PRC-023-1 – Transmission Relay Loadability, and also directed NERC, as the Electric Reliability Organization ("ERO"), to develop certain modifications to the PRC-023-1 standard through its Reliability Standards development process, to be completed and filed with the Commission by March 18, 2011. Attachment 1 to the SAR contains the directives and associated deadlines. The Order also directed development of two new Reliability Standards to address issues related to generator relay loadability and the operation of protective relays due to power swings. The standards-related directives in Order 733 are aimed at closing some reliability-related gaps in the scope of PRC-023-1.

The SAR's scope includes three standard development phases to address the standards-related directives in Order No. 733 directives. Phase I is focused on making the specific modifications to PRC-023-1 that were identified in the order; Phase II is focused on developing a new standard to address generator relay loadability; and Phase III is focused on developing requirements that address protective relay operations due to power swings.

Further details are available on the project page: http://www.nerc.com/filez/standards/SAR_Project%202010-13_Order%20733%20Relay%20Modifiations.html

Standards 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 Monica Benson,
Standards Process Administrator, at monica.benson@nerc.net or at 609.452.8060.

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