NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Relay Loadability Standard Drafting Team Meeting

February 15–16, 2007
Tampa, Florida

Draft Meeting Notes

Attendance — Chairman Charles Rogers brought the meeting to order. Due to severe winter weather, most flights from the north and east were cancelled and only the following team members attended the meeting:

- Charles Rogers
- Mark Carpenter
- Henry Miller
- Richard Young

Maureen Long served as a substitute for the team's coordinator, Richard Schneider, whose flight was amongst those that were cancelled.

Antitrust — There were no questions on the Antitrust Guidelines.

Agenda — Charles Rogers and the members present decided to draft responses to the comments submitted on the second draft of the standard, make conforming changes to the standard and implementation plan, and circulate the revised documents to the rest of the team for additional input.

Response to Comments — The drafting team developed a response to all the comments except for those comments related to modifications of violation severity levels. The drafting team sent the comments on violation severity levels to compliance personnel.

The most significant change to the standard was replacing "Reliability Coordinator" with "Planning Coordinator" for requirement 3. The team deliberated over this change and determined that, under the Functional Model, the Planning Coordinator is responsible for conducting long-range planning studies used to determine where to install equipment. The drafting team looked at this change as a "correction" that should be accepted by stakeholders.

The draft response to comments and the modifications to the implementation plan and standard are attached.

Next Activities — The drafting team made only minor modifications to the standard and the implementation plan and determined that they would seek the Standards Committee's approval to move the standard forward to ballot.

Schedule — The drafting team reviewed their project schedule and did not make any changes to the schedule.

No future meetings were planned.

Action Items:

1. Maureen Long will circulate a copy of the red line version of the standard and the implementation plan to the entire drafting team, along with the draft consideration of comments.
2. Maureen Long will send the comments on violation severity levels to compliance for their input.
3. Charles Rogers will ask the drafting team members to send comments to the entire team by close of business on Tuesday, February 20.
   - If the e-mails don't raise issues requiring discussion, then the team will submit its work to the Standards Committee.
   - If the e-mails do raise issues requiring discussion, then the team will hold a conference call to resolve the outstanding issues.
4. If the drafting team resolves all its issues and determines to move forward, Maureen Long will ask the Standards Committee and Standards Committee's Executive Committee to review the issue before its next regularly scheduled meeting (March 13, 2007).

The meeting ended around 4 p.m. on February 15, 2007.

Standard Development Roadmap

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

Development Steps Completed:

1. SAC approves SAR for posting on January 9, 2006.
2. The SAR was posted for comment from January 16, 2006 to February 15 2006.
3. The SAC approves development of the standard on May 12, 2006.
4. The JIC assigns development of the standard to NERC on June 15, 2006.
5. Drafting team post first draft for comments (August 16–September 29, 2006).

Description of Current Draft:

The drafting team considered the comments on the initial ballot and has posted its consideration of those comments and made conforming changes to the implementation plan. The drafting team also made conforming changes to bring the standard into compliance with the Reliability Standards Development Procedure, Version 6. The drafting team is posting the revised standards and implementation plan for a 30-day comment period from January 9–February 9, 2007.

Future Development Plan:

Anticipated Actions	Anticipated Date
1. Post for 30-day comment period.	January 9, 2007
2. Review comments from industry posting; post consideration of comments.	February 22, 2007
3. Post for 30-day pre-ballot period.	March 1–March 30, 2007
4. Conduct first ballot.	April 2–April 11, 2007
5. Consider and post response to comments on first ballot.	April 18, 2007
6. Conduct second ballot.	April 18–27, 2007
7. BOT adoption date.	May 2, 2007

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Definitions of Terms Used in Standard

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

None.

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A. Introduction

1. **Title: Transmission Relay Loadability**

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

3. **Purpose:** Protective relay settings shall not limit transmission loadability.

4. **Applicability:**

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

4.1.1 Transmission lines operated at 200 kV and above.

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

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

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

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

4.4. Planning Coordinators.

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

5.1. Requirement 1, Requirement 2, Requirement 4:

5.1.1 For circuits described in 4.1.1 and 4.1.3 above — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later.

5.1.2 For circuits described in 4.1.2 and 4.1.4 above — at the beginning of the first calendar quarter 39 months following applicable regulatory approvals.

5.2. Requirement 3: 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 (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: [Violation Risk Factor: High] [Time Horizon: Long Term Planning].

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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.

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

R1.2. Set transmission line relays so they do not operate at or below 115% of the highest seasonal 15-minute Facility Rating 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 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 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.

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

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

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. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

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

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

R3.1.1. This process shall include coordination with adjoining Planning Coordinator(s).

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

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

R4. Each Transmission Owner, Generator Owner, and Distribution Provider shall have 24 months after being notified by its Planning Coordinator pursuant to R3.3 to comply with R1 (including

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all sub-requirements) for each facility that is added to the Planning Coordinator's critical facilities list determined pursuant to R3.1. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

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C. Measures

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

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

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

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D. Compliance

1. Compliance Monitoring Process

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1.1. Compliance Monitoring Responsibility

1.1.1 Regional Entity.

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1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

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

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

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

1.4. Additional Compliance Information

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

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2. Violation Severity Levels: Transmission Owner, Generator Owner, and Distribution Provider

2.1. Lower:

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

2.2. Moderate:

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

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2.3. High:

2.3.1 NA

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

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

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

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3. Violation Severity Levels: Planning Coordinator

3.1. Lower:

3.1.1 N/A

3.2. Moderate:

3.2.1 N/A

3.3. High:

3.3.1 Does not provide the list to the appropriate Transmission Owners, Generator Owners, and Distribution Providers.

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3.4. Severe:

3.4.1 Does not have a process in place to determine facilities that are critical to the reliability of the electric system.

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3.4.2 Does not maintain a current list of facilities critical to the electric system,

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E. Regional Differences

1. None

F. Associated Documents

Determination and Application of Practical Relaying Loadability Ratings

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Attachment A

1. This standard includes any protective functions which could trip with or without time delay, on load current, including but not limited to:
   - 1.1. Phase distance
   - 1.2. Out-of-step tripping
   - 1.3. Switch-on-to-fault
   - 1.4. Overcurrent relays
   - 1.5. Communications aided protection schemes including but not limited to:
     - 1.5.1 Permissive overreach transfer trip (POTT)
     - 1.5.2 Permissive under-reach transfer trip (PUTT)
     - 1.5.3 Directional comparison blocking (DCB)
     - 1.5.4 Directional comparison unblocking (DCUB)
2. This standard includes out-of-step blocking schemes which shall be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.
3. The following protection systems are excluded from requirements of this standard:
   - 3.1. Relay elements that are only enabled when other relays or associated systems fail. For example:
     - Overcurrent elements that are only enabled during loss of potential conditions.
     - Elements that are only enabled during a loss of communications.
   - 3.2. Protection systems intended for the detection of ground fault conditions.
   - 3.3. Protection systems intended for protection during stable power swings.
   - 3.4. Generator protection relays that are susceptible to load.
   - 3.5. Relay elements used only for Special Protection Systems applied and approved in accordance with NERC Reliability Standards PRC-012 through PRC-017.
   - **3.6.** Protection systems that are designed only to respond in time periods which allow operators 15 minutes or greater to respond to overload conditions
   - 3.7. Thermal emulation relays which are used in conjunction with dynamic Facility Ratings
   - 3.8. Relay elements associated with DC lines
   - 3.9. Relay elements associated with DC converter transformers.

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Prerequisite Approvals
There are no other reliability standards or Standard Authorization Requests (SARs), in progress or approved, that must be implemented before this set of standards can be implemented.

Modified Standards
There are no other reliability standards or SARs, in progress or approved, that must be modified or retired as a result of this standard being implemented.

Compliance with Standards
Once this Transmission Relay Loadability Standard becomes effective, the responsible entities identified must comply with the requirements.

Proposed Effective Dates
Note: There are current ongoing activities, under the approval of the NERC Planning Committee, which essentially direct responsible entities to conform to the requirements of this standard. The due-dates for these activities are December 31, 2007 for circuits at 200 kV and above, and June 30, 2008 for 100–200 kV applicable circuits. The proposed effective dates for this standard reflect these ongoing activities.

The proposed standard will become effective as follows:

- 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 1, Requirement 2, Requirement 4:
  - For circuits described in 4.1.1 and 4.1.3 above (except for SOTF) — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later.
  - For circuits described in 4.1.2 and 4.1.4 above (including SOTF) — at the beginning of the first calendar quarter 39 months after applicable regulatory approvals.
- Requirement 3: Eighteen months following applicable regulatory approvals

The Relay Loadability Standard Drafting Team thanks all commenters who submitted comments on the second draft of the Reliability Loadability standard. This standard was posted for a 30-day public comment period from January 2 through February 7, 2007. The [Relay Loadability Standard Drafting Team] asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 32 sets of comments, including comments from more than 80 different people from more than 50 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team is recommending that the Standards Committee authorize moving these standards forward.

Based on stakeholder comments and a review of the latest version of the Functional Model, the drafting team revised Requirement 3 to read as follows:

- 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. [Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]

This change re-assigns responsibility for making the determination of the facilities critical to the reliability of the BES from the Reliability Coordinator to the Planning Coordinator. Because this task is performed in the 'long-term planning' time frame, this task should be assigned to the Planning Coordinator.

Based on stakeholder comments, the drafting team made the following minor clarifying changes to the standard:

- Modified the applicability section to use the phrase, 'applied to the facilities defined in 4.1.1 through 4.1.4 ' rather than 'applied according 4.1.1 through 4.1.4.'
- Modified r1.10 to clarify that the transformer nameplate rating must be expressed in amperes
- Modified r1.10 to replace the word, 'applicable' with the following qualifying phrase:
  - Including the forced cooled ratings corresponding to all installed supplemental cooling equipment.

Based on stakeholder comments, the drafting team added the following to the list of exceptions in Attachment A of the standard:

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

Based on stakeholder comments, the drafting team also made the following revisions to the effective dates in the implementation plan:

- For circuits described in 4.1.1 and 4.1.3 above (except for SOTF) — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later.
- For circuits described in 4.1.2 and 4.1.4 above (including SOTF) — at the beginning of the first calendar quarter 39 months after applicable regulatory approvals.

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Relay-Loadability.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 Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@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.

Commenter		Organization	Industry Segment									
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1.	Jay Farrington	Alabama Electric Cooperative, Inc.	✓									
2.	Ben Pilleteri	Alabama Power Company	✓									
3.	Dan Shield	Alberta Electric System Operator	✓									
4.	Anita Lee	Alberta Electric System Operator		✓								
5.	Ken Goldsmith	ALT										✓
6.	Robert Rauschenbach	Ameren	✓									
7.	James Sorrels, Jr.	American Electric Power	✓				✓	✓				
8.	Randy Spacek	Avista Corp.	✓									
9.	Dave Rudolph	BEPC										✓
10.	Dean Bender	Bonneville Power Administration	✓									
11.	Alan Gale	City of Tallahassee					✓					
12.	Ed Thompson	Con Edison	✓									
13.	Richard J Pienkos	Consumers Energy Company			✓	✓	✓					
14.	Carl Kinsley	Delmarva Power & Light Company	✓									
15.	Sonia Walden	Dominion Virginia Power	✓									
16.	Paul Smith	Duke Energy Carolinas	✓									
17.	Tom Seeley	E.ON-U.S.	✓									
18.	Charlie Fink	Entergy	✓									
19.	Ed Davis	Entergy Services, Inc.	✓									
20.	Eric Senkowicz	Florida Reliability Coordinating Council		✓								
21.	Linda Campbell	Florida Reliability Coordinating Council		✓								
22.	Mark Bennett	Gainesville Regional Utilities					✓					
23.	Phil Winston	Georgia Power Company	✓									
24.	Phil Winston	Georgia Power Company	✓									
25.	Steve Waldrep	Georgia Power Company	✓									
26.	Hong-Ming Shuh	Georgia Transmission Corporation	✓									
27.	Dick Pursley	GRE										✓
28.	Steve Carter	Gulf Power Company	✓									
29.	Roger Champagne	Hydro Quebec TransEnergie	✓									
30.	Roger Champagne	Hydro-Québec TransÉnergie (HQT)	✓									
31.	Ron Falsetti	IESO		✓								
32.	Kathleen Goodman	ISO- New England		✓								
33.	Bill Shemley	ISO-New England		✓								
34.	Brian Thumm	ITC Transmission	✓									
35.	Eric Ruskamp	LES										✓
36.	Donald Nelson	MA. Dept of Tele. and Energy									✓	

Commenter		Organization	Industry Segment									
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37.	Robert Coish	Manitoba Hydro	✓		✓		✓	✓				
38.	Tom Mielnik	MidAmerican										✓
39.	Joe Knight	Midwest Reliability Organization										✓
40.	Terry Bilke	MISO										✓
41.	Joseph Stewart	Mississippi Power Company	✓									
42.	Carol Gerou	MP										✓
43.	Herb Schrayshuen	National Grid	✓									
44.	Greg Campoli	New York ISO		✓								
45.	Ralph Rufrano	New York Power Authority	✓									
46.	Brian Hogue	Northeast Power Coordinating Council										✓
47.	Guy Zito	Northeast Power Coordinating Council										✓
48.	Murale Gopinathan	Northeast Utilities	✓									
49.	Al Boesch	NPPD										✓
50.	Jerad Barnhart	NSTAR	✓									
51.	David Kiguel	Ontario Hydro	✓									
52.	Todd Gosnell	OPPD										✓
53.	Ben Morris	Pacific Gas & Electric	✓									
54.	Chifong Thomas	Pacific Gas & Electric	✓									
55.	Ed Taylor	Pacific Gas & Electric	✓									
56.	Glenn Rounds	Pacific Gas & Electric	✓									
57.	Tom Siegel	Pacific Gas & Electric	✓									
58.	Vahid Madani	Pacific Gas & Electric	✓									
59.	Richard J. Kafka	Pepco Holdings, Inc. Affiliates	✓									
60.	Mark Kuras	PJM		✓								
61.	Alvin Depew	Potomac Electric Power Company	✓									
62.	Evan Sage	Potomac Electric Power Company	✓									
63.	Eric Grant	Progress Energy – Florida	✓									
64.	D. Bryan Guy	Progress Energy Carolina, Inc.	✓		✓		✓					
65.	Eithar Nashawati	Progress Energy Carolinas	✓									
66.	Jerry Blackley	Progress Energy Carolinas	✓									
67.	C. Robert Moseley	Public Service Commission of South Carolina									✓	
68.	David A. Wright	Public Service Commission of South Carolina									✓	
69.	Elizabeth B. Fleming	Public Service Commission of South Carolina									✓	
70.	G. O'Neal Hamilton	Public Service Commission of South Carolina									✓	
71.	John E. Howard	Public Service Commission of South									✓	

Commenter		Organization	Industry Segment									
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		Carolina										
72.	Mignon L. Clyburn	Public Service Commission of South Carolina									✓	
73.	Phil Riley	Public Service Commission of South Carolina									✓	
74.	Randy Mitchell	Public Service Commission of South Carolina									✓	
75.	Dick Curtner	Public Service of New Mexico	✓									
76.	Malkiat Dhillon	Sacramento Municipal Utility District	✓									
77.	Jonathan Sykes	Salt River Project	✓									
78.	Pat Huntley	SERC Reliability Corp.										✓
79.	Gene Henneberg	Sierra Pacific Power Company	✓									
80.	Marion Frick	South Carolina Electric & Gas Company	✓									
81.	Bridget Coffman	South Carolina Public Service Authority	✓									
82.	J.T. Wood	Southern Co. Transmission	✓									
83.	Jim Busbin	Southern Co. Transmission	✓									
84.	Marc Butts	Southern Co. Transmission	✓									
85.	Roman Carter	Southern Co. Transmission	✓									
86.	Charles Sufana	Sufana Engineering, Inc.								✓		
87.	George Pitts	Tennessee Valley Authority	✓									
88.	Meyer Kao	Tennessee Valley Authority	✓									
89.	Ron Falsetti	The IESO, Ontario		✓								
90.	Bill Middaugh	Tri-State Gen. and Trans. Ass'n.	✓									
91.	Jim Haigh	Western Area Power Administration										✓
92.	Paul Rice	Western Electricity Coordinating Council	✓									
93.	Neal Balu	WPSR										✓
94.	Mike Ibold	Xcel Energy	✓									
95.	Pam Oreschnik	XEL										✓

Index to Questions, Comments, and Responses

1. **The draft standard specifies that the Reliability Coordinator is to determine "which of the facilities in its Reliability Coordinator Area are critical to the reliability of the Bulk Electric System" for the purpose of application of this standard to 100 kV–200 kV circuits. Do you agree that the Reliability Coordinator is the proper functional entity for this requirement?**

Summary Consideration: After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. Planning Coordinators do have responsibility for conducting assessments to determine whether to install additional facilities. For that reason, the drafting team did modify the standard to assign this requirement to the Planning Coordinator.

The drafting team also modified R3 to include the purpose of identifying these critical facilities – the purpose of identifying the critical facilities in the two standards is not the same and would not be expected to result in the same list of facilities.

Question #1			
Commenter	**Yes**	**No**	**Comment**
PJM		☑	Planning Coordinators would be better suited to determine critical facilities. I don't like the use of this concept without a defdinition or process put forth to extablish this critical circuits idea. Will a compliance review be performed on my determination of criticality of circuits? Will I be second guessed by a NERC auditor if I say I have no critical lines?
Response: Planning Coordinators do have responsibility for conducting assessments to determine whether to install additional facilities. For that reason, the drafting team did modify the standard to assign this requirement to the Planning Coordinator. The measure only requires that there be a methodology and that the list resulting from that methodology be provided to the listed entities. There is no measure of the quality of the methodology.			
Entergy Services, Inc.		☑	We think the RC should not be the exclusive determinator of - critical to the reliability of the BES -, especially since the other entities are required to expend resources to comply with that determination. Therefore, we suggest the responsible entites under R3 be changed from - RELIABILITY COORDINATOR SHALL DETERMINE - to - RELIABILITY COORDINATOR, IN CONJUNCTION WITH TRANSMISSION OWNERS, GENERATION OWNERS, AND DISTRIBUTION PROVIDERS SHALL DETERMINE. This change should be made in R3, along with our suggested change to the Appicability comment in response to Question 6 below.
Response: Planning Coordinators do have responsibility for conducting assessments to determine whether to install additional facilities. For that reason, the drafting team did modify the standard to assign this requirement to the Planning Coordinator. According to V3 of the Functional Model, the Planning Coordinator is responsible for coordination suggested in your comment.			

<table>
<tr><th colspan="4">Question #1</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td>Alberta Electric System Operator - AESO</td><td></td><td>☑</td><td>The WECC currently maintains the bulk transfer path catalog which provides a list of the critical facilities. It may be more appropriate for the RRO to be the entity responsible for making the determination on critical facilities.</td></tr>
<tr><td colspan="4">Response: FERC has directed NERC to refrain from assigning requirements to the RRO because the RRO is not an owner, operator or user of the bulk power system. Please see the summary consideration of comments. After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. The RRO can register to be a Planning Coordinator.</td></tr>
<tr><td>Western Electricity Coordinating Council</td><td></td><td>☑</td><td>The Regional Reliability Organization (RRO) previously had some responsibility for determining the "operationally significant" facilities. NERC may want to continue its inclusion since the bulk transfer path catalog, which contained many such facilities, is maintained by our RRO.</td></tr>
<tr><td colspan="4">Response: In the October NOPR on Standards, FERC indicated that NERC should refrain (Paragraph 54 - 59) from assigning requirements to the RRO because the RRO is not an owner, operator or user of the bulk power system. Please see the summary consideration of comments. After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. The RRO can register to be a Planning Coordinator.</td></tr>
<tr><td>Florida Reliability Coordinating Council</td><td></td><td>☑</td><td>The shift from RRO to RC accountability for determination of "circuits critical to the reliability of the Bulk Electric System" is a significant step change in current NERC Reliability philosophy. One concern we have is for consistency across the Regions and the change in this standard would shift that concern to consistency across RCs of the Interconnections.

The second concern is that this will effectively shift some of the RC functions and accountabilities over to a role as a Compliance monitor. Some of the compliance elements associated with the new RC relationships may create inadvertent coordination and compliance measuring conflicts between the new Regional Entities, the RCs and the transmission owners that will ultimately have to comply with PRC-023.
Based on the above we recommend removal of the RC related requirements and applicabilities until NERC (as the ERO) can better define the criteria or methodology for determining "circuits critical to the reliability of the Bulk Electric System" or establish a standardized Rliebility Impact Based methodology for RCs to use when creating the critical circuits list (circuits between 100 kV and 200 kV).</td></tr>
<tr><td colspan="4">Response: In the October NOPR on Standards, FERC indicated that NERC should refrain (Paragraph 54 - 59) from assigning requirements to the RRO because the RRO is not an owner, operator or user of the bulk power system. Please see the summary consideration of comments. After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. The RRO can register to be a Planning Coordinator.</td></tr>
</table>

Question #1			
Commenter	**Yes**	**No**	**Comment**
There is nothing in the standard that assigns the Reliability Coordinator (now Planning Coordinator) any compliance monitoring responsibilities.			
American Electric Power		☑	We believe that the RC should work in conjunction with the Bulk Electric System owners and operators to help make the determination.
Response: Please see the summary consideration of comments. After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. According to V3 of the Functional Model, the Planning Coordinator is responsible for coordination suggested in your comment.			
Progress Energy Carolina, Inc.		☑	Not as written. Requirement 3.1 requires that the RC have a process to determine critical 100-200kV lines that must meet relay loadability requirements. Req 3.1.1 requires that the RC coordinate with adjoining RCs. The standard should also include a provision, Req 3.1.2, that requires the RC process to also coordinate with the facility Transmission Owner(s) in addition to the adjoining RCs.
Response: Please see the summary consideration of comments. After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. According to V3 of the Functional Model, the Planning Coordinator is responsible for coordination suggested in your comment.			
Northeast Power Coordinating Council	☑	☑	NPCC participating members believe the Reliability Coordinator should determine which facilities in its area, are critical to the BPS irrespective of voltage level and an approved Regional performance based methodology should be used to consistently determine this on a wide area basis. However it is recognized that many Regions may not have an approved Bulk Power System methodology and in this instance they should utilize the Drafting Team's critera.
Response: Please see the summary consideration of comments. After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. According to V3 of the Functional Model, the Planning Coordinator is responsible for coordination suggested in your comment. Note that the standard does require the responsible entity to have defined criteria – this is not an option.			
IESO	☑	☑	
Hydro-Québec TransÉnergie (HQT)	☑	☑	For the existing system, HQT believe the Reliability Coordinator should determine which facilities in its area, are critical to the BPS irrespective of voltage level. An approved Regional performance based methodology should be used to consistently determine this on a wide area basis. The same could apply for the Planning Authority/Coordinator for future equipment additions since the relay settings would be done during project development. However it is recognized that many Regions may not have an approved Bulk Power System methodology and in this instance they should utilize the Drafting Team's

Question #1			
Commenter	**Yes**	**No**	**Comment**
			critera.
Response: Please see the summary consideration of comments. After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. According to V3 of the Functional Model, the Planning Coordinator is responsible for coordination suggested in your comment. Note that the standard does require the responsible entity to have defined criteria – this is not an option.			
Pacific Gas and Electric	☑		The Regional Reliability Organization (RRO) previously had some responsibility for determining the "operationally significant" facilities. NERC may want to continue its inclusion since the bulk transfer path catalog, which contained many such facilities, is maintained by our RRO.
Response: In the October NOPR on Standards, FERC indicated that NERC should refrain (Paragraph 54 - 59) from assigning requirements to the RRO because the RRO is not an owner, operator or user of the bulk power system. Please see the summary consideration of comments. After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. The RRO can register to be a Planning Coordinator.			
Manitoba Hydro	☑		However, the Reliability Coordinator should coordinate on the methodology to identify critical facilities with the Transmission Owners. Also, this procedure to identify critical facilities should be coordinated with the procedure to identify critical assets in the Critical Infrastructure Protection Standards (CIP-002-1) to avoid potential confusion or conflict (i.e. two similar lists developed by different procedure).
Response: Please see the summary consideration of comments. After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. According to V3 of the Functional Model, the Planning Coordinator is responsible for coordination suggested in your comment. The drafting team modified R3 to include the purpose of identifying these critical facilities – the purpose of identifying the critical facilities in the two standards is not the same and would not be expected to result in the same list of facilities.			
MidAmerican	☑		The standard does not appear to require the Reliability Coordinator to do this in conjuncton with the other Applicable Entities. R3.1.1 states This process shall include coordination with adjoining Reliability Coordinator(s). The MRO recommends that this requirement be expanded to include the other Applicable Entities listed in this standard. The critical facilities list required by this standard, should be coordinated with the critical facilities lists required by other standards in as much as it it possible.
Response: Please see the summary consideration of comments. After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. According to V3 of the Functional Model, the Planning Coordinator is responsible for coordination suggested in your comment.			

Question #1			
Commenter	**Yes**	**No**	**Comment**
The drafting team modified R3 to include the purpose of identifying these critical facilities – the purpose of identifying the critical facilities in the two standards is not the same and would not be expected to result in the same list of facilities.			
Pepco Holdings, Inc. Affiliates	☑		
ITC Transmission	☑		
National Grid	☑		
Public Service Commission of South Carolina	☑		
Consumers Energy Company	☑		

2. **The Relay Loadability Drafting Team added a Mitigation Time Horizon for each requirement. Do you agree with the Mitigation Time Horizon for each requirement in the proposed standard? If not, please identify any requirement with a time horizon you feel is incorrect.**

Summary Consideration: Many commenters indicated a lack of familiarity with 'mitigation time horizons' (now called simply 'time horizons'). These were introduced in NERC's ERO Application and again in NERC's Non-governance Compliance Filing as one of the elements used to determine the size of a sanction. (See Appendix 4 Paragraph 3.12 of the ERO Application and Item 65 of the Non-governance Compliance Filing.)

Requirements that must be mitigated in real-time operations would have a larger sanction than those that could be mitigated over a longer time period. The comment form provided a list of possible mitigation time horizons. The latest version of the Reliability Standards Development Procedure did not include mitigation time horizons – this was an omission in bringing the manual into conformance with the latest ERO Rules of Procedure and this omission should be corrected with the next revision to the manual. In the meantime, stakeholders will be asked to comment on and approve mitigation time horizons as they are developed with standards. The alternative is to have these time horizons identified outside the standard development process, and stakeholders indicated they wanted a voice in the selection of all the compliance elements within standards.

Question #2			
Commenter	**Agree**	**Do not agree**	**Comment**
Manitoba Hydro			Before we can comment on the appropriate assignment of Mitigation Time Horizons we need a better explanation of the concept of Mitigation Time Horizons and how Mitigation Time Horizons will be used to determine sanctions. MH appreciates the consideration of comments response on the Mitigation Time Horizon issue from the Balance Resources and Demand SDT. However their response does not sufficiently address our concerns. It would be helpful for stakeholder consideration of assignment of Mitigation Time Horizons, MH suggests, if NERC could post a clear proposed definition of the term Mitigation Time Horizon and provide a fuller explanation of intended use to determine the size of sanctions. We gather that the concept is that violations involving more immediate or real-time activities will generally incur larger panalties than violations involving longer time frames. This is very vague. The suggested posting could serve as a draft addition to the Reliability Standards Development Procedure. Neither the comments in this form nor the ERO Rules of Procedure provide a definition or sufficient explanation. The term "Mitigation Time Horizon" does not appear in the Rules of Procedure or any other NERC document as far as we know. The term "Violation Time Horizon" on the Rules of Procedure is

Question #2			
Commenter	**Agree**	**Do not agree**	**Comment**
			obviously related.
Response: Mitigation Time Horizons have been renamed, 'Time Horizons' to better match the terminology in the ERO Rules of Procedure. Please see the summary consideration of comments for a more detailed explanation of the specific locations where you can find more information on time horizons.			
PJM		☑	Not sure what they mean in relation to a determination of non-compliance and the associated penaties.
Response: In accordance with the Sanctions Guidelines, the sanction associated with the violation of a real-time requirement should be larger than a violation of a requirement that is performed for the long-term planning horizon because there is more time to mitigate the violation that occurred for the long-term planning requirement.			
MidAmerican		☑	Mitigation Time Horizons are described near the top of this comment form. The description of the Mitigation Time Horizons states The ERO Rules of Procedure include the use of mitigation time horizons as one element used to determine the size of sanctions. Can the drafting team inform the Registered Ballot Body where the ERO definition of Mitigation Time Horizons can be found along with documentation describing how the mitigation time horizons will be used in determining penalties. Mitigation Time Horizons are not listed as a Performance Element of a Reliability Standard in the Reliability Standards Development Procedure Version 6 adopted by the NERC BOT on November 1, 2006. As such, it does not seem appropriate to include them in any Reliability Standards. The comment form description of Mitigation Time Horizons further states The drafting team used the following guidelines in developing mitigation time horizons for each requirement, whereas the final statement in the description of the Violation Risk Factors states The following categories of violation risk factors were approved with the latest version of the Reliability Standards Development Procedure. Like the Violation Risk Factors, the categories of Mitigation Time Horizons should also be approved and incorporated into the Reliability Standards Development Procedure in order to ensure that the definitions are consistent for all NERC Reliability Standards. The MRO cannot vote to approve a standard that includes Mitigation Time Horizons until the drafting team can produce ERO documented definitions and the documented manner in which the Mitigation Time Horizons will be used to determine penalties.
Response: Please see the summary consideration of comments. The drafting team needs to move the standard forward and can't wait for another issuance of the Reliability Standards Development Procedure.			

Question #2			
Commenter	**Agree**	**Do not agree**	**Comment**
Western Electricity Coordinating Council Pacific Gas and Electric		☑	While we agree that the horizons are probably adequate we have two areas of concern. The first is the discrepancy between the 39 months in A.5.1.2 and the 24 months in B.R4. Secondly we suggest that horizons be implemented to accommodate correction of issues of Security Level violations that may be found in the future.
Response: The implementation plan includes a total of 39 months to allow the development of the initial list of circuits critical to reliability of the BES between 100-200 kV. The 24 months is to comply with changes subsequent to the initial list. The last comment mixes time horizons and violation severity levels. While both elements are used in determining the size of a sanction, they represent different things – the time horizon identifies the time period associated with the requirement – since a requirement in real-time has very little time for mitigation that requirement should have a larger sanction than a requirement that, if violated could be mitigated over several years (like a long-term planning requirement) Violation Severity Levels identify how badly an entity 'missed' achieving a requirement. Complete failure is rated as severe and would lead to a higher sanction than a 'lower' rating where an entity was almost fully compliant.			
ITC Transmission		☑	There is insufficient material describing the development and use of mitigation time horizons for inclusion in the Reliability Standards. It is premature to include them in these version of the Standards. When the Reliability Standards Development Procedure is updated to include a detailed description of their meaning and usage, only then should they be included in a Reliability Standard.
Response: Please see the summary consideration of comments. The drafting team needs to move the standard forward and can't wait for another issuance of the Reliability Standards Development Procedure.			
Florida Reliability Coordinating Council		☑	The "Mitigation Time Horizons" are not part of the Reliability Standards Development Procedure, version 6.0, adopted by NERC BOT, 11/1/2006. As such it is not clear why these were included in this standard. We understand the description of "Mitigation Time Horizons" is provided in the comment form and the concept of "Violation Time Horizons" is included in the Sanctions Guidelines, appendix 4B (NERC Compliance Filing to FERC dated October 18th, 2006), but we feel these horizons are part of a broader policy issue

Question #2			
Commenter	**Agree**	**Do not agree**	**Comment**
			and since their use is not clearly stipulated in the NERC standards process, including them in the standards will cause unnecessary confusion to stakeholders and regulators. The mitigation (or violation) time horizons should be clearly stipulated in the Reliability Standards Development Procedure prior to their use in any standard (from a policy perspective).
Response: Please see the summary consideration of comments. The drafting team needs to move the standard forward and can't wait for another issuance of the Reliability Standards Development Procedure.			
Entergy Services, Inc.	☑		
Pepco Holdings, Inc. Affiliates	☑		
National Grid	☑		
Progress Energy Carolina, Inc.	☑		
Northeast Power Coordinating Council	☑		
American Electric Power	☑		
Public Service Commission of South Carolina	☑		
Consumers Energy Company	☑		
Hydro-Québec TransÉnergie (HQT)	☑		
IESO	☑		

3. The latest version of the Reliability Standards Development Procedure requires that each standard include "Violation Severity Levels" rather than "levels of non-compliance." "Violation Severity Levels" identify how badly an entity violated each requirement, and are not linked to the reliability-related impact of violating a requirement. (The reliability-related impact of violating a requirement is now identified in the "Violation Risk Factor" appended to each requirement.) Do you agree with the Violation Severity Levels for each of the proposed standards? If you disagree with any of the Violation Severity Levels for the proposed standards, please identify the standard and requirement you feel has an incorrect Violation Severity Level.

Summary Consideration:
The drafting team modified D2.4.1 to read as follows:
Relay settings do not comply with any of the requirements in R1.1 through R1.13

Question #3			
Commenter	**Agree**	**Do not agree**	**Comment**
Entergy Services, Inc.		☑	The VRF for R1 is HIGH which we suggest should be MEDIUM. The specification of a particular criteria will not cause cascading outages. The use of a VRF of HIGH for relays should be applied to relays not set to the criteria.
Response: The first draft of this standard included VRFs and the comment form included a question on the VRFs. Since the comments provided did not indicate a need to change the VRFs, none of these were changed, the drafting team did not ask the question again.			
Alberta Electric System Operator - AESO		☑	1. Section D 2.2.1 "Evidence that the relay settings comply with criteria in R1.1 through 1.13 exists but is incomplete or incorrect for one or more of the requirements" - we recommend adding the word "applicable" before the word "criteria" since the present wording could imply that compliance is required for all of the criteria. 2.Section D 2.4.1 stipulates that it's a Severe violation level if "Relay settings do not comply with R1.1 thought R1.13 or evidence does not exist to support that relay settings comply with one of the criteria in R1.1 through R1.13". Firstly, "thought" should be changed to "through"; secondly, we think that it would be more appropriate to have different violation severity levels corresponding with the number of non-compliance to the sub-requirements (R1.1 to R1.13), instead of assigning the highest severity level for non-

Question #3			
Commenter	Agree	Do not agree	Comment
			compliance with any one of the sub-requirements.
Response: This is not a measure- after reviewing performance the compliance monitor looks at the violation severity levels to see which level best describes the performance. The word applicable was not added. The typographical error was corrected. Because an entity can choose 'any' of the criteria in R1.1 to R1.13, only one of these is applicable for any specific facility.			
Western Electricity Coordinating Council Pacific Gas and Electric		☑	We suggest the wordings for the specific sections in D.2. be changed to those shown below: D.2.1.1 The applicable 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. D.2.2.1 Evidence that relay settings comply with the applicable criteria in R1.1 through R1.13 exists, but is incomplete or incorrect for one or more of the requirements. D. 2.4.1 Relay settings do not comply with any requirement R1.1 through R1.13 or evidence does not exist to support that relay settings comply with any one of the criteria in R1.1 through R1.13.
Response: This is not a measure- after reviewing performance the compliance monitor looks at the violation severity levels to see which level best describes the performance. The word applicable was not added. Because an entity can choose 'any' of the criteria in R1.1 to R1.13, only one of these is applicable for any specific facility. The drafting team modified the violation severity level to adopt your suggestion			
National Grid		☑	Section D, 2.4.1 states a Severe level violation applies when "Relay settings do not comply with R1.1 through R1.13 or evidence does not exist to support that relay settings comply with one of the criteria in R1.1 through R1.13." National Grid agrees that non-compliance of relay settings should constitute

Question #3			
Commenter	**Agree**	**Do not agree**	**Comment**
			a Severe level violation. However, we believe that in cases where "Relay settings comply with one of the criteria in R1.1 through R1.13, but evidence does not exist to support that the relay settings comply" that a High level violation should apply.
Response: The proposal mixes two different requirements with a single violation severity level. Violation severity levels need to be assigned for each requirement and identify how badly the requirement was missed. If an entity has 'no evidence' it is at the 'severe' level, not at the 'high' level.			
Florida Reliability Coordinating Council		☑	Although the violation severity levels (Lower, Moderate, High and Severe) are defined in the comment form provided and described as the basis for the DT's determinations, the levels are NOT defined in the current Reliability Standards Development Procedure. The term 'violation severity levels' is referenced generally in the Reliability Standards Development Procedure, version 6.0, adopted by NERC BOT, 11/1/2006 in the 'Compliance Elements of a Standard' section, as follows: (Violation Severity Levels) - 'Defines the degree to which compliance with a requirement was not achieved. The violation severity levels, are part of the standard and are balloted with the standard, and developed by the NERC compliance program in coordination with the standard drafting team.' Since the standards procedure does NOT include the definitions for Lower, Moderate, High and Severe, our main concern, again, is from a policy perspective. Although the definitions are included in the comment form, we feel this track will lead to confusion among stakeholders and regulators in this and other standard development activities. The process is requesting the industry to ballot and comment on a concept (Lower, Moderate, High and Severe) that is defined outside the reliability standards process and as such is subject to revisions and interpretations outside the process as well. This appears inappropriate and at the extreme will lead to inconsistent understanding, measurement and enforcement of compliance actions. The levels should be defined in the Reliability Standards Development Procedure prior to inclusion in balloting any standards.
Response:			
IESO Northeast Power Coordinating Council		☑	(1) Section D 2.4.1 stipulates that it's a Severe violation level if "Relay settings do not comply with R1.1 thought R1.13 or evidence does not exist to support that relay settings comply with one of the criteria in R1.1 through R1.13. We find this confusing, and does not correspond to R1, which says:

Question #3			
Commenter	**Agree**	**Do not agree**	**Comment**
Hydro-Québec TransÉnergie (HQT)			"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 …" We interpret this to mean that an entity is compliant if it meets at least one of the criteria listed in R1 through R1.13. To add clarity to the text, we suggest rewording D 2.4.1 as follows: "Relay settings do not comply with at least one of R1.1 thought R1.13 or evidence does not exist to support that relay settings comply with at least one of the criteria in R1.1 through R1.13." (2) Section D, 3.3.1 (Reliability Coordinator does not provide the list…) should be moved to the Severe level, 3.4.2 (Reliability Coordinator does not maintain a current list of facilities…) should be moved to the High level. From our perspective there are 3 key elements in establishing the list of facilities critical to the reliability of the bulk electric system: 1) determining the facility list, 2) communicating the list to asset owners, and 3) maintaining the list. The intent of R3 is to ensure that facility owners are informed of which of their facilities are critical to the reliability of the electric system in order that they design/set their relays to meet R1. Communicating the list of critical facilities is, in our view, one of the most important requirements. There is no such thing as a partial communication and so it's a case of either full compliant (communication) or flat out non-compliant (no communication at all). We therefore propose that 3.3.1 be moved to the Severe level. If we accept the above argument, the requirement to maintain the list seems secondary. Note that maintaining the list does imply that the list has been communicated to the facility owners, and the requirement to maintain the list can be partially met. On the other hand, having communicated the list to the owners while not maintaining the list would still meet the intent of this standard. We therefore propose that 3.4.2 (Reliability Coordinator does not maintain a current list of facilities..) be moved to the High level.

Question #3			
Commenter	**Agree**	**Do not agree**	**Comment**
			Determining which facilities are critical to the reliability of the electric system is also an important first step. We agree that 3.4.1 should be retained at the Severe level, but propose to revise the sentence to read: "Reliability Coordinator does not have a process in place to determine, or evidence that it has determined, facilities that are critical to the reliability of the electric system."
Response: The drafting team modified D2.4.1 to read as follows: - Relay settings do not comply with any of the requirements in R1.1 through R1.13			
MidAmerican		☑	The MRO does not agree with the proposed Violation Severity Levels due to the fact that they have not been fully vetted in the Standards Development Process. A process which includes being held up for public comment, scrutiny and balloting.
Response:			
American Electric Power		☑	We believe that the appropriate violation severity level designation for the violation described in Section D-2.2.1 should be "Lower" rather than "Moderate". The language in D-2.2.1 and D-2.4.1 is ambiguous and should include references to the specific requirements that apply.
- **Response:**			
Pepco Holdings, Inc. Affiliates	☑		
ITC Transmission	☑		
Progress Energy Carolina, Inc.	☑		
Public Service Commission of South Carolina	☑		
Consumers Energy	☑		

Question #3			
Commenter	**Agree**	**Do not agree**	**Comment**
Company			
Manitoba Hydro	☑		
PJM	☑		

4. **Are you aware any requirement in this standard that has an unnecessary adverse impact on energy markets? Please identify the requirement and its adverse impact here.**

Summary Consideration: No unnecessary adverse impacts on energy markets were identified.

Question #4			
Commenter	**No Unnecessary Adverse Impacts**	**Unnecessary adverse impact on markets**	**Comment**
Entergy Services, Inc.	☑		
Pepco Holdings, Inc. Affiliates	☑		
Western Electricity Coordinating Council	☑		
ITC Transmission	☑		
National Grid	☑		
Pacific Gas and Electric	☑		
Progress Energy Carolina, Inc.	☑		
Northeast Power Coordinating Council	☑		
Public Service Commission of South Carolina	☑		
Consumers Energy Company	☑		
Manitoba Hydro	☑		
Hydro-Québec TransÉnergie (HQT)	☑		
IESO	☑		
PJM	☑		
MidAmerican	☑		

5. **The draft implementation plan for PRC-023 proposes that the standard will be implemented following applicable regulatory approvals and the conclusion of the ongoing activity cited above. Based on these observations, the standard drafting team does not feel that PRC-023 will require field testing. Do you think that a field test period for PRC-023 is necessary?**

Summary Consideration: There was no consensus on whether a field test is needed. The commenters who indicated a field test is needed, had a variety of reasons for suggesting that a field test is needed. The drafting team will forward these comments to the Director, Compliance for use in determining whether to recommend a field test. Extensive review and field testing has already been conducted in conjunction with the 'NERC Recommendation 8a' and 'beyond zone 3' activities that were performed under the direction of the NERC SPCTF and NERC Planning Committee.

Question #5			
Commenter	**No field testing is necessary**	**Field testing is necessary**	**Comments**
Sufana Engineering, Inc.		☑	I would think that at least some of the lines should be tested to see if any of the NERC proposed requirements are actually able to be used.
Response: Extensive review and field testing has already been conducted in conjunction with the 'NERC Recommendation 8a' and 'beyond zone 3' activities that were performed under the direction of the NERC SPCTF and NERC Planning Committee.			
Pacific Gas and Electric		☑	Yes. field testing is recommended. Successful implementation depends on close communication between the Planning Authority, Transmission Operator and Reliability Coordinator. Requirements for documentation of compliance need to be clearly defined and understood by all parties.
Response: After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. According to V3 of the Functional Model, the Planning Coordinator is responsible for coordination suggested in your comment. A field test of the coordination should not be needed as this is coordination that should already be taking place.			

Florida Reliability Coordinating Council		☑	This standard is extremely technical in nature as evidenced by the development of PRC-023 Reference document. The new concepts being addressed in the standard will also result in the involvement of new industry participants that have not been historically, involved in the NERC Reliability Standards process and the accompanying compliance concepts. Based on the above, we recommend that a field test of the standard, to validate the measures and compliance elements, may highlight discrepancies and deficiencies in the measurability of the standard. We also feel that the field test may add additional insight and detail which could be added to the reference document or training material associated with the adoption of the standard.
Response: After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. According to V3 of the Functional Model, the Planning Coordinator is responsible for coordination suggested in your comment. A field test of the coordination should not be needed as this is coordination that should already be taking place. The drafting team cannot identify any requirements that are assigned to industry participants that haven't been involved in standards. Extensive review and field testing has already been conducted in conjunction with the 'NERC Recommendation 8a' and 'beyond zone 3' activities that were performed under the direction of the NERC SPCTF and NERC Planning Committee.			
American Electric Power		☑	While field testing may be difficult for PRC-023, it would be useful to provide a transition period wherein violations are reviewed, but not subject to sanction or fine.
Response: The purpose of a field test is to verify that the requirements, measures and compliance elements are correct and can be implemented as written. The purpose of a field test is not to provide entities with time to follow the standard without sanctions for non-compliance. Extensive review and field testing has already been conducted in conjunction with the 'NERC Recommendation 8a' and 'beyond zone 3' activities that were performed under the direction of the NERC SPCTF and NERC Planning Committee.			

Public Service Commission of South Carolina		☑	The PSCSC believes field testing is necessary, since NERC is significantly expanding the scope of facilities to which this standard will apply.
Response: Extensive review and field testing has already been conducted in conjunction with the 'NERC Recommendation 8a' and 'beyond zone 3' activities that were performed under the direction of the NERC SPCTF and NERC Planning Committee.			
Hydro-Québec TransÉnergie (HQT) IESO Northeast Power Coordinating Council		☑	HQT believe the need for further field testing depends on the outcome of the final determination of what constitutes the BPS. Additional time or effort for field testing may be required to not only come into compliance if large additional portions of the lower voltage electric system are included, but to test the validity and coordination of the concepts contained in this standard. During NERC SPCTF's previous efforts pertaining to Beyond Zone 3 the application of the concepts were somewhat confined. HQT believe the Standard as written should not be restricted to voltage classifications and should be applied to performance based BPS criteria elements.
Response: The term 'BPS' is not used in the standard. Extensive review and field testing has already been conducted in conjunction with the 'NERC Recommendation 8a' and 'beyond zone 3' activities that were performed under the direction of the NERC SPCTF and NERC Planning Committee. After additional deliberation, the drafting team assigned R3 to the Planning Coordinator. According to V3 of the Functional Model, the Planning Coordinator is responsible for coordination suggested in your comment. A decision on what is critical at voltages lower than 200 kV is, under the revised standard, the decision of a Planning Coordinator - and is largely a local issue. A field test of the coordination should not be needed as this is coordination that should already be taking place.			
MidAmerican		☑	The MRO believes that field testing is necessary so as to gauge if the time being allotted to the operators to respond is appropriate and to make sure the equipment is reasonably protected.
Response: Extensive review and field testing has already been conducted in conjunction with the 'NERC Recommendation 8a' and 'beyond zone 3' activities that were performed under the direction of the NERC SPCTF and NERC Planning Committee.			

The drafting team is not aware of any real-time operating issues (associated with the implementation of the proposed requirements starting in 2003 with zone 3 NERC recommendation 8a requirements) that have been identified during the review and testing that has already taken place.			
Western Electricity Coordinating Council	☑		While we don't necessarily believe that additional field testing is necessary for the proposed standards, standard 1.3.2 is different from the original exception 4 and will not have been tested. This also changes the requirements for series-compensated lines.
Response: The old 'technical exceptions' have been re-crafted as requirements. Although there have been some changes, these changes are not technically substantive.			
Entergy Services, Inc.	☑		
Pepco Holdings, Inc. Affiliates	☑		
Alberta Electric System Operator - AESO	☑		
ITC Transmission	☑		
National Grid	☑		
Progress Energy Carolina, Inc.	☑		
Consumers Energy Company	☑		
Manitoba Hydro	☑		
PJM	☑		

6. If you have any other comments on this set of standards or its implementation plan that you have not already submitted above, please provide them here.

Summary Consideration: Based on stakeholder comments, the drafting team added the following to the list of exceptions in Attachment A of the standard:

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

The drafting team also made some minor clarifying changes as follows:

- modified the applicability section to use the phrase, 'applied to the facilities defined in 4.1.1 through 4.1.4 ' rather than 'applied according 4.1.1 through 4.1.4.'
- modified R1.10 to clarify that the transformer nameplate rating must be expressed in amperes
- modified R1.10 to replace the word, 'applicable' with the following qualifying phrase:
    - including the forced cooled ratings corresponding to all installed supplemental cooling equipment.

The drafting team also made the following revisions to the effective dates in the implementation plan:

- For circuits described in 4.1.1 and 4.1.3 above (except for SOTF) — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later.
- For circuits described in 4.1.2 and 4.1.4 above (including SOTF) — at the beginning of the first calendar quarter 39 months after applicable regulatory approvals.

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Commenter	**Comment**
Sufana Engineering, Inc.	This standard totally lacks fully worked out examples as to how to set the zone 3 relays. I would like to see complete detailed examples for each of the Relay Phase Settings sections. As the standard is presented now, it is essentially useless to the actual relay setter. Each example should have a complete ratings list of all of the equipment on the line (both summer and winter, short time, emergency, etc), the actual procedure of doing the relay setting (including comparing the apparent impedance versus the results based on loading), and final values for the sample lines. For each R1.xx, the first example should include a two terminal line. The second example for each R1.xx should include a three terminal line that has a very weak source. Each example should also show different relay shapes, i.e. mho, lens, trapezoidal, mho with a notched out section, trapezoidal with a notched out section, etc. There should also be fully worked out examples for current only based relays. If the relay has the ability to notch out part of the characteristic around the line load angle, then

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	questions as to how close to the angle should be addressed, i.e. if 30 degrees is the load angle, is plus/minus 5 degrees (thus the area from 25 to 35 degrees is notched out) OK? How close to the loadability point should the relay setting be should also be addressed. For all examples, a case that is deemed acceptable and one that is considered in violation should be presented. I have had to set several 3 terminal lines that had a weak source that was actually an autotransformer tied to the line via a breaker. The resultant apparent impedance was so high that any setting would have been violation of the normal approach of using 1.15 times Irating. The result was that sequential tripping (which I consider to be not a good way to do things) was going to happen if the communications failed and that dual and perhaps triple layers of communication were needed. A fully worked out example of this type case should be included. So the bottom line is that for each example, I would like to see the entire equipment rating list, the fault study results, and how the actual setting was determined. If it takes 20 pages to show the example, so be it. Examples that are only a two terminal lines will be considered by me to be insufficient.
Response: The standard establishes requirements but does not include procedures on 'how' to meet those requirements.	
Entergy Services, Inc.	1. The industry has determined that NERC reliability standards need to be more definitive as to which entities the standards are Applicable. Therefore, Entergy strongly suggests that all Applicability assignments in ALL standards and requirements be changed to be very specific. Recognizing the greater Applicability specified in this draft of the standard we think greater specificity is required. Therefore, we suggest the Applicability of each standard be changed to - ALL REGISTERED xxx, NO ADDITIONAL CONDITIONS NOR LIMITATIONS WILL BE ADDED TO THE APPLICABILITY OF THIS STANDARD, where xxx is the functional entity to whom the standard applies. Therefore, the Applicability of PRC-023-1 should not be Transmission Owners but should be changed to - ALL REGISTERED TRANSMISSION OWNERS, NO ADDITIONAL CONDITIONS NOR LIMITATIONS WILL BE ADDED TO THE APPLICABILITY OF THIS STANDARD; Reliability Coordinators should be changed to - ALL REGISTERED RELAIBILITY COORDINATORS, NO ADDITIONAL CONDITIONS NOR LIMITATIONS WILL BE ADDED TO THE APPLICABILITY OF THIS STANDARD;Generation Owners but should be changed to - ALL REGISTERED GENERATION OWNERS, NO ADDITIONAL CONDITIONS NOR LIMITATIONS WILL BE ADDED TO THE APPLICABILITY OF THIS STANDARD; Distribution Providers but should be changed to - ALL REGISTERED DISTRIBUTION PROVIDERS, NO ADDITIONAL CONDITIONS NOR LIMITATIONS WILL BE ADDED TO THE APPLICABILITY OF THIS STANDARD. The Applicability sections 4.1.2 and 4.1.4 should be changed from - AS DESIGNATED BY THE RELIABILITY COORDINATOR AS CRITICAL TO THE RELIABILITY OF THE BULK ELECTRIC SYSTEM -

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	to - AS DESIGNATED BY THE RESULTS OF R3 OF THIS STANDARD. 2. In Applicability sections 4.2 and 4.3, please clarify the meaning, or applicability, of the term - applied according to 4.1.1 through 4.1.4. It is not clear what is meant by that phrase. 3. R3 contains the nebulous term - ARE CRITICAL TO THE RELIABILITY OF THE BULK ELECTRIC SYSTEM. This phrase is too vague and should be replaced by - ARE LIMITING FACILITIES DEFINED BY IROLs. 4. Measure M1 contains R1 and R4 in parentheses. We do not understand the meaning. Please re-write M1 so the relevance of R1 and R4 is clear.
Response: 1. The recommendation is for a format change, not a technical change. The existing language assigns the responsibility for identification to a functional entity and seems to be easier to understand. Under 'applicability' if there are no qualifying statements associated with a functional entity then the applicability is ALL – for example if there are no qualifying statements associated with the term, Transmission Owner, then the applicability is ALL Transmission Owners. 2. The drafting team adopted your suggestion and modified the applicability section to use the phrase, 'applied to facilities defined in 4.1.1 through 4.1.4.' 3. The term, 'IROLs' was not adopted in the revised standard because this is not the only criteria that may be used when identifying facilities critical to the reliability of the Bulk Electric System. 4. The parentheses indicate that the measure applies to both R1 and R4.	
Pepco Holdings, Inc. Affiliates	PRC-023-1 Section F lists a reference document -PRC-023 Reference — Determination and Application of Practical Relaying Loadability Ratings-. There is no statement in the actual standard as to whether the information and requirements contained within the reference document are part of the standard. The introductory sentence in the Reference Document states -This document is intended to provide additional information and guidance for complying with the requirements of Reliability Standard PRC-023.- It says it provides information and guidance, not requirements. Yet there are specific requirements contained within the reference document (such as Switch-on-to-Fault Setting Requirements). Either all requirements should be listed in the actual standard itself, or the standard should indicate there are additional requirements contained within the Reference Document. In addition, Appendix D of the Reference Document states the following: -For existing SOTF schemes, the SOTF protection must not operate when a breaker is closed into an unfaulted line

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	which is alive at a voltage exceeding 85% of nominal from the remote terminal. For SOTF schemes commissioned after formal adoption of this report, the protection must not operate when a breaker is closed into an unfaulted line which is energized from the remote terminal at a voltage exceeding 75% of nominal.- The report is dated January 9, 2007, but the PRC-023-1 standard is not yet approved. The stated requirement mentioned above should not reference the date of formal adoption of the report, but the date of the formal adoption of the standard.
Response: The reference document, while it may include the word, 'must', does not include any mandatory requirements. The Appendix D of the Reference Document provides a discussion of how SOTF relates to relay loadability and provides guidance in how to consider SOTF in accordance with Attachment A, 1.3 of the Standard. The drafting team modified the title of the reference document was modified to omit, 'PRC-023-1'.	
Alberta Electric System Operator - AESO	1. Thermal Relays - Some direction should be provided regarding the use of themal emulation relays, either in the standard exclusions or in the reference document. 2. We have a concern about loading to 115% of the 15 minute rating for overhead lines. Specifically because ratings are often based on maximum allowable sag according to the National Electric Safety Code and intentionally loading above that level represents a safety code violation. 3. Determining and granting allowance for technical exceptions was previously done by the RRO. If this responsibility is assigned to the Reliability Coordinator there may not be consistency across the region. 4. R1.1 - We suggest changing the duration of the 150% loading requirement from the 4 hour facility rating to the continuous rating. Four hour ratings are not presently used within Alberta. 5.R1.3.2 - We believe that Exception 4 provided adequate loadability without the additional 15% current margin in PRC-023. The maximum power is calculated based on 1.05 p.u. voltages. For the bus voltage to dip to 0.85 p.u. the system impedance will have thavd to increase very significantly as a result of other system changes, thus significantly reducing the maximum power transfer and its equivalent current. Many of the technical exceptions that have presently been accepted in teh WECC based on Exception 4 would no longer be permitted. Changing the loadability requirement at this time may cause unreasonable hardship on entities to be in compliance by January 1, 2008.
Response: 1. The drafting team assumes you are using thermal emulation relays in conjunction with dynamic Facility Ratings.	

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Dynamic relays are beyond the scope of relays addressed within this standard. The drafting team added thermal emulation relays to the list of exclusions. 2. The standard does not require any entity to have a 15-minute rating. Any 15-minute rating that is developed should be developed in a manner that allows the system operator to resolve the limit before any NESC violations occur. 3. The standard does not include any technical exceptions – compliance with all requirements is mandatory. Compliance monitoring is the responsibility of NERC as the ERO – and the ERO may delegate this responsibility to the Regional Entity. 4. The standard does not include a '4 hour Facility Rating' – the standard says, 'for the available defined loading duration nearest 4 hours'. 5. The old 'technical exceptions' have been re-crafted as requirements. Although there have been some changes, these changes are not technically substantive.	
Western Electricity Coordinating Council	1. Some thermal emulation relays are used in SPS, but since they could operate independent of the SPS we wonder if there ought to be some discussion of them in the standard exclusions, or in the reference. 2. We suggest that, for clarity, "Facility" and "Facility Rating" definitions be copied from the "Glossary of Terms Used in Reliability Standards" to be included in either the standard or the reference. 3. We have concerns about loading to 115% of the 15 minute rating for overhead lines. Those ratings are often based on maximum allowable sag according to the National Electric Safety Code. Intentionally loading above that level may be in violation of the safety code. 4. Previously the RRO had responsibility in determining allowance of technical exceptions, which provided consistency throughout the entire region. Moving those responsibilities to the Reliability Coordinators (RC) may change that consistency, thus treating entities differently depending on their RC. 5. R1 - There is no longer a loadability rating based on breaker rating (Exception 3). 6. R1.1 - We suggest changing the duration of the 150% loading requirement from the 4 hour facility rating to the continuous rating. We have found that entities typically have continuous and

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	short term, i. e., 15 minute, ratings defined, but not 4 hour ratings. 7. R1.3.2 - We believe that Exception 4 provided adequate loadability without the additional 15% current margin in PRC-023. The maximum power is calculated based on 1.05 per unit voltages. For the bus voltage to dip to 0.85 per unit the system impedance will have had to increase very significantly as a result of other system changes, thus significantly reducing the maximum power transfer and its equivalent current. Many of the technical exceptions that have presently been accepted in the WECC based on Exception 4 would no longer be permitted. Changing the loadability requirement at this time may cause unreasonable hardship on entities to be in compliance by January 1, 2008. 8. R1.4 - The current calculation for Exception 5 could have been based on Exception 2, 3, or 4 but was frequently based on 4. Since 4 has been significantly changed it will also change the allowed loadability of R1.4. We believe that this is another reason to keep R1.3.2 to be determined in the same manner as Exception 4.

Response:

1. The drafting team assumes you are using thermal emulation relays in conjunction with dynamic Facility Ratings. Dynamic relays are beyond the scope of relays addressed within this standard. The drafting team added thermal emulation relays to the list of exclusions.

2. When a standard is approved, the new terms defined with that standard are transferred from the standard to the Glossary. The definitions do not remain with the standard once the standard is approved. Note that there are no new terms associated with the proposed standard.

3. The standard does not require any entity to have a 15-minute rating. Any 15-minute rating that is developed should be developed in a manner that allows the system operator to resolve the limit before any NESC violations occur.

4. The standard does not include any technical exceptions – compliance with all requirements is mandatory. Compliance monitoring is the responsibility of NERC as the ERO – and the ERO may delegate this responsibility to the Regional Entity.

5. The breaker rating was used as a proxy for source impedance which was more restrictive than the actual source impedance. Therefore, R1.3.2 captures the essence of the requirement to have a loadability rating based on breaker rating.

6. The standard does not include a '4 hour Facility Rating' – the standard says, 'for the available defined loading duration nearest 4 hours'.

7, 8. The old 'technical exceptions' have been re-crafted as requirements. Although there have been some changes, these changes are not technically substantive.

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ITC Transmission	Requirements R1.1 and R1.2 are written to allow transmission relays to be set as a percentage of "seasonal Facility Ratings" for a "defined loading duration." Not all transmission owners assign seasonal ratings to their transmission facilities (i.e., there is one rating for the full year). Also, not all transmission owners have time-of-use ratings (e.g., 4-hour emergency ratings, 15-minute emergency ratings). Perhaps there is a way to clarify the requirements to ensure an entity with one rating is not in jeopardy of being found non-compliant sinply for not having a seasonal rating. ITC Transmission recommends a footnote to that effect, indicating that if seasonal ratings do not apply for a particular facility, then the full-year rating is to be used. Similarly, a footnote could also clarify that if a short-term or emergency rating has not been established for a particular facility, then the normal rating would apply (which, notably, would be more conservative than an emergency rating, since emergency ratings are generally higher than normal ratings).
Response: The standard does not require that an entity have multiple seasonal ratings. If you don't have multiple seasonal ratings, use the one seasonal rating that you do have. The standard does not include a '4 hour Facility Rating' – the standard says, 'for the available defined loading duration nearest 4 hours'. A footnote is not needed.	
National Grid	1. The schedule for Switch-On-To-Fault (SOTF) protections applied on elements 200 kV and above is the same as the Beyond Zone 3 schedule for the phase protections referenced in section A.4.1.2 and A.4.1.4 applied on elements 100 kV to 200 kV. The Effective Date for the Standard should be modified to include all SOTF protections in the Effective Date in Section A.5.1.2. 2. In Section B, Requirement R1.10 additional specificity should be provided regarding the word applicable in the phrase "applicable maximum transformer nameplate rating. 3. In Section B, Requirement R1.11 additional specificity should be provided to clarify that the word supervision refers to blocking tripping of the transformer overload protection relays when the top oil or winding hot spot temperature is below the value specified in the Standard. 4. Investigation of protective relay misoperations sometimes identifies firmware problems that cause a relay to operate in an manner not intended by the manufacturuer. How would compliance be assessed in a case where a firmware problem is identified that prevents a relay from meeting the the relay loadability requirements? What process would exist for granting exemption from the Standard for such a problem that would affect all Entities that have applied the protective relay in question?

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Response: 1. The drafting team modified the implementation plan to support this suggestion – the revised effective dates are as follows: o For circuits described in 4.1.1 and 4.1.3 above (except for SOTF) — January 1, 2008 or the beginning of the first calendar quarter following applicable regulatory approvals, whichever is later. o For circuits described in 4.1.2 and 4.1.4 above (including SOTF) — at the beginning of the first calendar quarter 39 months after applicable regulatory approvals. 2. The drafting team modified R1.10 to eliminate the word, 'applicable' and added the following phrase: including the forced cooled ratings corresponding to all installed supplemental cooling equipment. 3. The word, 'supervision' should be understood by protection engineers and the lack of comments on this requirement led the drafting team to believe that clarifying language is not needed. 4. The scope of this standard does not address relay misoperations. Misoperations and their associated mitigations are addressed in PRC-004. Entities are responsible for complying with the standard.	
Pacific Gas and Electric	(1)There are some technical differences between PRC-023 and NERC Recommendation 8a that need to be resolved. For example, NERC Recommendation 8a defined a term called the "Emergency Ampere Rating" of a transmission line, which includes an explanation of how this rating should be determined. NERC PRC-023 requires the use of a "Facility Rating" to determine the circuit loadability. The term "Facility Rating" should be similarly defined so as not to cause confusion later, especially if no field test is applied before implementation. Other specific comments on the technical differences between PRC-023 and NERC Recommendation 8a will be sent in by the WECC Relay Work Group. (2) Need more clarification on SPS Schemes. Are all SPS schemes exempt or only the ones that meet NERC Reliability Criteria? Some SPS schemes are local in nature, do not affect neighboring utilities and failure of one of these schemes would not result in cascading events. These local SPS schemes may not be designed with the same degree of redundancy as SPS schemes that are in the WECC catalog and have been reviewed by the WECC RAS Reliability Subcommittee. (3) Are line thermal overload schemes exempt? They are designed to take corrective action to prevent overloading a transmission line and by their nature may prevent loading the transmission line to levels required by R1.1 through R1.13. (4) If a relay setting is found to not comply, is there an implementation period to comply?

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	(5) No sanctions have been associated with the different levels of non-compliance. When will these be defined?
Response: 1. Facility Rating is a defined term that encompasses the intent of the term, "Emergency Ampere Rating". Please see the response to WECC's comments. 2. This standard only exempts those SPS' that are subject to the NERC Reliability Standards PRC-012 through PRC-017. 3. The drafting team assumes you are using thermal emulation relays in conjunction with dynamic Facility Ratings. Dynamic relays are beyond the scope of relays addressed within this standard. The drafting team added thermal emulation relays to the list of exclusions. 4. Entities are responsible for complying with the requirements. The compliance monitoring section of the standard indicates that compliance may be assessed through annual self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor. 5. The sanctions guidelines are part of the ERO Rules of Procedure.	
Florida Reliability Coordinating Council	We have a concern with the associated "reference document", PRC-023 Reference. It is not clear how and where this document was developed. We understand that the document was created from previous references developed by the SPCTF. We would like to see a more formal vetting process of "reference documents". The cover sheet indicates it was prepared by the SPCTF of the NERC Planning Committee and that it is version 1.0, dated January 9, 2007. In review of meeting histories, we were not able to find the "formal" approval or adoption process of this document by the SPCTF or the PC. We recommend that reference documents of this type should include a revision history along with approval history indicating what quality checks were performed on the document and which body (SPCTF, PC) sponsored its development and approved its publication. If a reference document is created outside of the standards process it should contain an appropriate disclaimer stating so, to ensure that it is clear that Reliability standard in effect during compliance activities take precedence over references. This would be important, especially if synchronization or interpretation conflicts existed between the reference document and the Reliability standard.
Response: The drafting team will submit the 'final' version of the reference document to the Standards Committee for approval to post the document with the approved standard. This is the process in the latest version of the Reliability Standards Development Procedure. If the Standards Committee directs the drafting team to get the approval of the Planning	

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Committee, then the drafting team will do that. At this point, the drafting team doesn't consider the reference document to be 'final'. The drafting team will consider adding a version history to the final version of the document submitted for formal approval to the Standards Committee. Standards are mandatory and enforceable and technical references are not. Restating this at the front of the technical reference does not seem necessary.	
Northeast Power Coordinating Council	Violation Risk Factors are an integral part of Reliability Standards development process and the comment form should include a question on appropriateness of the assigned risk factors to seek industry consensus.
Response: The first draft of this standard included VRFs and the comment form included a question on the VRFs. Since the comments provided did not indicate a need to change the VRFs, none of these were changed, the drafting team did not ask the question again.	
American Electric Power	In response to question 4 above (there is no comment space provided), it is difficult to assess this impact on energy markets without having had the standard deployed. The referenced field test (or transition period) would be beneficial to make such a determination.
Response: Extensive review and field testing has already been conducted in conjunction with the 'NERC Recommendation 8a' and 'beyond zone 3' activities that were performed under the direction of the NERC SPCTF and NERC Planning Committee. To date no market issues associated with the proposed requirements have been identified.	
Alabama Electric Cooperative, Inc.	1. R4 should have provisions for temporary and technical exceptions on newly identified critical circuits. 2. The implementation dates in 5.1.2 and 5.2 needs to be clarified. For the initial list, the 39 month clock should start after the RC designates a circuit as critical.
Response: R4 does include 24 months for entities to comply with the requirements following the date of notification. Most stakeholders seemed to support the 24 months so it was not changed to 39.	
Consumers Energy Company	1. Section 2.4.1, the word "thought" should be "through". 2. This standard is extremely difficult to understand and apply without the use of PRC-23 Reference Guide. This guide is very helpful in understanding what is being suggested and where the margins come from. However, it fails to give any guidance for criteria R1.13. Some examples or suggestions on how to use this criteria would be most helpful. Also, while the PRC-23 Reference Guide is listed as an "Associated Document" in Section F, it would seem helpful to mention this reference guide earlier in the standard (possibly as a note) as its use is important to correct application of these criteria.

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Response: The typo in 2.4.1 was corrected. R1.13 was intentionally put in the standard and left open-ended so entities would have an opportunity to identify and justify alternate ratings if needed based on conditions not covered by the other subrequirements of R1. It is anticipated this will be seldom utilized. Because use of the reference is not mandatory, it is not referenced in the body of the requirements in the standard.	
Manitoba Hydro	A.3. The word "Transmission loadability" need to be clearly defined/clarified. Suggested wording: 1. Protective relay settings shall not limit transmission loadability which was determined by regional approved operating guidelines. 2. Protective relay settings shall not limit practical loading capability of a circuit A. 4.2 Who is to ensure that the IPPs(generator owners) will comply with this standard? B. R1.1. “The highest seasonal Facility Rating of a circuit” is not clearly defined in this draft of the standard. It has been changed from the original term of “Emergency Ampere Rating” of a circuit Does this imply that the highest possible loading limit (which could be lower than the thermal rating) of a circuit can be used as the highest seasonal Facility Rating? B. R1.10 and R1.11 How to distinguish transformer fault protection relays from overload protection relays On R1.11, if overload protection is desired, can we add a phase overcurrent relay with a definite time delay of not less than 15 minutes, regardless of trip setting? R1.11, the transformer overload relays must not trip at 150% of the maximum applicable nameplate rating. Does this mean the MVA rating of the transformer? Considering the need to evaluate loadability at 0.85 pu voltage, does this imply a requirement to set overcurrent relays at 165%? B. R1.13 Manitoba Hydro appreciates the SDT adding this option which addresses our concern about being able to use stability limits as the maximum rating of a circuit.

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	We are curious to know, if we have a hard limit on the circuit, why is it nessesary to add another 15% on this limitation? For example, we have transformers which the manufacturer has subsequently advised us to restrict operation such that there is no loading above the continuous loading. In this case, being forced to add a margin would only subject the transformer to potential failure. I believe that this could be written such that the aim would be to have a 15% margin unless there was evidence that equipment damage would occur. B. In general Mantioba Hydro does not have major concerns with R2 but would like the SDT to consider two suggestions which we believe would add value to R2 specifically as it applies to R1.13. Manitoba Hydro see the benefit in getting agreement between the Transmission Operator, the Planning Authority, and the Reliability Coordinator in developing limits. In some areas Mantioba Hydro would agree that this should be adequate. However areas that are close to a seam in any of these functions (TO, PA, or RC) should be seeking greater stakeholder approval. Manitoba Hydro suggest that this could be accomplished by having the entitiy publish an operating guide for the facility in question. An operating guide would require the entity to seek further stakeholder input, and would still require, thorough other NERC standards, the approval of the appropriate functions under the NERC functional model. The second concern is in the approval of ratings. In some jurisdictions, Mantioba is one, ratings which are different for the nameplate ratings would have to have the approval of a Professional Engineer with the right to practice within that jurisdiction. This is required because there is a safety issue regarding the operation of the equipment. This calls into question the legality of requiring various function under the NERC model to aprove (or agree with ratings) unless they have the legal right to set that rating. Mantioba Hydro would suggest that name plate ratings should always be considered as appropriate limits. However when nameplate limits cannot be used for any reason, the entity owning the equipment will submit a notice, sealed by a Professional Engineer with the right to practice within the jurisdiction that the equipment resides, informing the TO, PA, and the RC why the nameplate ratings cannot be used and advising the variuos functions of the new ratings. The standard writing team should remember that a Professinal Engineer has a legal responsibility to stakeholders beyond the firm for which they practice, and that obligation should provide the independence sought for in this requirement. It also has the benefit of avoiding the potential situation where the TO, PA, and RC do not agree on a proposed rating.

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	C. What would be considered as acceptable evidence? Attachment A 2. A word PERMANENTLY should be added before "block trip…"? 3.3 I am not quite sure what exactly this mean?

Response:

A3 - Most commenters seemed to accept the use of the term, 'transmission loadability' without having this term formally defined.

A4.2 - The drafting team is not responsible for verifying that IPPs register with NERC and comply with requirements in NERC's reliability standards.

B. R1.1. - 'Facility Rating' is a defined term. If an entity has only one seasonal rating for all seasons then that would be the highest seasonal Facility Rating of a circuit – similarly if an entity has 5 seasonal ratings, then comparing the 5 ratings and identifying the one that has the highest numerical value will result in the 'highest seasonal Facility Rating of that circuit.'

B. R1.10 and R1.11 - Typically, protective relays are designed to detect faults and not overload conditions. This standard addresses fault protecting relays.

Overload protection has a long response time as detailed in R1.11.
(adding a phase overcurrent relay with a definite time delay of not less than 15 minutes, regardless of trip setting) This would satisfy the standard as written, however an unusually low setting would be outside the spirit of the standard and would not represent a sound operating practice.

R1.11 - The drafting team replaced the word, 'applicable' with the following phrase:

- including the forced cooled ratings corresponding to all installed supplemental cooling equipment.

The standard requires that relay loadability is evaluates at 0.85 pu voltage. The nameplate rating of a transformer is expressed in MVA based on 1.0 pu voltage which translates to an ampere rating on that same basis. The true thermal limit of the transformer is based on current, not MVA. For clarity, the drafting team modified the requirement to clarify that the

<table>
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<tr><td colspan="2">transformer nameplate rating is expressed in amperes.

B. R1.13 - The 15% margin is for inherent error in the relay and sensing circuits. If overload protection is desired, please apply R1.11.

The entities listed in R2 already have responsibility for coordination.

There is no reliability-related reason to add the proposed new requirement.

The drafting team did modify R1.10 in response to other stakeholder comments and replaced the word, ‘applicable’ with the following phrase:
including the forced cooled ratings corresponding to all installed supplemental cooling equipment.

Each facility owner has the right to establish the rating of its facilities.

C - Any evidence (documentation or a demonstration) that shows that a specific relay meets any one of the criteria in R1 is acceptable. This could include a review of actual relay settings in the field, a review of a data base dump of relay settings and facility ratings, or a wide variety of other methods. The drafting team did not require any specific type of evidence to ensure that no entity would be required to invest resources solely for the purpose of demonstrating compliance.

Attachment A 2- Most commenters seemed to understand the intent of this item without further clarification.

3.3 - This exempts schemes installed specifically to protect during stable power swings. Note that stable power swings occur, have been experienced, and are predictable in locations where load is substantially isolated from generation.</td></tr>
<tr><td>Hydro-Québec TransÉnergie (HQT)</td><td>Violation Risk Factors are an integral part of Reliability Standards development process and the comment form should include a question on appropriateness of the assigned risk factors to seek industry consensus.</td></tr>
<tr><td colspan="2">Response: The first draft of this standard included VRFs and the comment form included a question on the VRFs. Since the comments provided did not indicate a need to change the VRFs, none of these were changed, the drafting team did not ask the question again. Question 6 allows entities to provide comments on any part of the standard, including VRFs.</td></tr>
<tr><td>IESO</td><td>VRFs are now an integral part of the standards, which as a whole, require industry consensus for development and approval. Yet, there is no question asked on the concurrence on the violation risk factor levels for this draft, despite the fact that there are now new requirements assigned to the Reliability Coordinators. Is it an oversight, or is it an assumption that the assigned VRFs are acceptable to the industry?</td></tr>
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	In either case, we feel strongly that this question should be asked in order to provide the SDT an assessment of the acceptability of the assigned risk levels, although we do not disagree with any of the assigned risk levels.
Response: The first draft of this standard included VRFs and the comment form included a question on the VRFs. Since the comments provided did not indicate a need to change the VRFs, none of these were changed, the drafting team did not ask the question again. Question 6 allows entities to provide comments on any part of the standard, including VRFs.	
PJM	In R1.5, weak-source systems needs to be defined. In R1.6, remote to load needs to be defined. In R1.7 remote from generation stations and load center terminal needs to be defined. in R1.8 and R1.9, remote to the system needs to be defined. In R1.11, highest opertor established should be highest owner established. All instances of Reliability Coordinator in R3 and R4 should be changed to Planning Coordinator.
Response: The reference document provides additional discussion about the items listed and the drafting team will make a formal request to the Standards Committee to have the reference document posted with the approved standard. Most stakeholders accepted these terms without formal definitions. The drafting team did replace the Reliability Coordinator with the Planning Coordinator in R3 and R4.	
MidAmerican	1. Several companies in the MRO use line ratings of other than 4 hours. The MRO recommends the addition of a conversion factor for those companies using emergency ratings not consistent with what is stated in the standard. In lieu of a conversion factor, a standard line rating issued by NERC would be acceptable. 2. The MRO is concerned about what appears to be the forced assumption of risk with respect to overload levels and time durations that said overloads must be held. The MRO believes that it should be up to the Transmission Owner to determine the amount of risk they are willing to assume based on their own risk analysis. 3. In the Measures section under M3, the applicable entities listed for which the list of critical facilities must be provided to is not consistent with the applicable enities listed in R3 which M3 refers. 4. In the Violation Severity section, under violations for TOs, GOs, and DPs the definition of a

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	Severe Violation is not complete. 5. The MRO is concerned that this standard is removing some inherent thermal overload protection from the bulk electric system. In its response to comments the SAR drafting team stated - The emergency loadability of equipment should be reflected in the equipment ratings, and the fault protective relay should not be responsible for relieving emergency loading concerns. Controlling of emergency load should be left to system operators. - The fact is that fault protection also provides, admittedly crude, overload protection and MRO believes there is increased inherent risk to the bulk electric system in the sentiment of the SAR drafting team's second statement. In NERC Recommendation 8a it is stated - It is not practical to expect operators will always be able to analyze a massive, complex system failure and to take the appropriate corrective actions in a matter of a few minutes - and yet this is what this standard is expecting. Something like 400 transmission circuits tripped during August 14 blackout with no significant thermal overload damage. If the requirements of this standard had been met prior to August 14, 2003, would equipment damage have further delayed restoration? The MRO believes that a risk analysis should be conducted before implementing this standard. 6. The MRO believes this draft of the standard is too prescriptive. The equipment owner should be deciding the appropriate level of risk with regard to thermal overload and loss of life. The SDT should not decide the level of risk for the transmission owners. The standard is a good guide but too prescriptive. If during the largest blackout is US history, the existing system, group of standards, and relay set points separated the system in time to prevent significant equipment damage so that the system could be restored virtually without incident; then implications of changing relay setting philosophy should be studied carefully. For example, what is the time overload characteristic of wave traps compared to line conductors? How will system operators know when equipment damage is imminent in order to take that equipment out of service on time? 7. The effective dates for lines operated at 100kV to 200 kV and transformers, as designated by the regional reliability organization as critical to the reliability of the electric system in the region should be one year after the regional reliability organization has made this designation. It would seem reasonable that owners should not be expected to even start review of the 100kV OS circuits until the Region has defined the specific circuits. A date that the RROs are required to make this designation should be recommended by the SDT and added to the implementation plan. 8. Regarding the implementation plan, one would have expected an implementation time frame of

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	the stated durations strictly for identifying initial areas of non-compliance, and defining a plan to become compliant, with subsequent dates provided for becoming fully compliant. Eleven months after establishment of the standard is not a reasonable time frame for implementing all setting changes, and certainly not for design changes if required. It would appear that NERC is depending on all participants to have proceeded with reviews and actions as indicated in the initial zone 3 exercise. Perhaps regions/owners had every right to not proceed until the proposed standard is in force. Perhaps many of the efforts have proceeded, but should the proposed standard require that they all did? 9. The MRO feels that the more appropriate violation risk factor is medium because implementing this standard will not prevent the initiation of a blackout event. 10. The MRO has a concern with the 15 percent additional margin applied to the facility rating. This can be considered a negative margin with regard to protecting against thermal overload. The SAR indicates that protection should not unnecessarily limit the loadability of the system, it does not state that protection should be sacrificed or removed. This approach is outside the intention of the SAR. Again it should be up to the equipment owner to assess the appropriate overloading philosophy. 11. Does this standard expose the TO etc. to legal risk if there is damage to the public, violating vertical clearances for example? 12. If we are relying on the operator to prevent overloads, are the associated metering, communication, and human machine interface systems, (not to mention the human involvement, designed and maintained with equivalent reliability to the protection system? Also, the SCADA system may be down therefore the operator may not be able to assume the role of preventing equipment damage. 13. There should be a classification that allows the transmission owners with stability limited lines to perform studies which allow relay settings to identify the conditions the relay will actual see under extreme conditions. The .85 p.u. voltage and power factor angle of 30 degrees criteria may not be appropriate for all cases. 14. This standard removes the option of using zone three relays to provide more reliable system operation a. For internal lines – it may not be possible to set an out of step relay to block tripping on a

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	true out of step condition. Moving blinders in may make it impossible to detect fast moving swings. b. On interties: It may not be possible to set relays to detect the fastest swing to be able to trip the tie – as a consequence, undesired tripping of other lines may occur. 15. This standard seems to be precluding the concept of TOs etc. applying to use other settings than prescribed by this standard as was the case with zone 3 issue. A TO should be allowed to use relay settings other than based on the prescribed criteria if it can be demonstrated there is no benefit to applying the prescribed criteria in a given situation but there is, in fact, a negative impact on the TO's system. 16. In M1 and M2 it should be further clarified what is meant by evidence. The draft standard states the "The relay loadability reliability standard has been specifically developed to not interfere with system operator actions, while allowing for short-term overloads, with sufficient margin to allow for inaccuracies in the relays and instrument transformers." But for what scenario or number of contingencies is this statement accurate? 17. If a study is conducted to show that the 150% setting for zone 3 is not necessary, and the Transmission Owner wants to protect equipment with a more appropriate trip setting of say 125 percent, would the Transmission Owner have to prove that the setting is good for Category C for example; the Category C is listed in our question because the Transmission Owner typically is required only to plan for Category D only when the risk and consequences indicates there is a need to plan for such an event? The Transmission Owner can always come up with scenarios of contingencies that will trip a line or transformer, even at the 150 percent setting and not allow the operator time to react. Should the four hour rating be replaced with a one hour rating given that the four hour rating may be used to allow operator action rather than require relay or automatic control actions to remove a disturbance in a more timely fashion?

Response:

1. The standard does not include a '4 hour Facility Rating' – the standard says, 'for the available defined loading duration nearest 4 hours'.

2. There is no requirement to allow overloads to persist – the requirement is to prevent the relay from responding to overloads before the operators have time to take action. This standard does not preclude the operators from responding to overloads in time periods shorter than 15 minutes.

R3 and M3 require the list of critical facilities to be provided to TOs, GOs and DPs. The version of the standard that was posted was correct.

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4. The version of the standard that was posted was complete.

5. The preliminary implementation of the proposed requirements and stakeholder comments both indicate that this standard is set at an acceptable level.

This standard balances loadability with response of protective relaying to heavy overloads.

6. Most stakeholders indicated support of the standard as proposed. The drafting team crafted the requirements so that they identify 'what' criteria must be met, and left the details of 'how' to achieve those requirements in the reference document

7. The responsible entity has at least 21 months after the list is developed by the Planning Coordinator to become compliant. Most entities should already be mostly compliant with this standard.

8. Most commenters seemed to support the implementation plan as proposed. This standard was developed to codify some of the criteria that was identified as necessary to mitigate relays from contributing to cascading blackouts. The activities to address this have been ongoing since early 2004 – and entities have stated that they are conforming to what have been 'BOT directed activities'.

9. The first draft of this standard included VRFs and the comment form included a question on the VRFs. Since the comments provided did not indicate a need to change the VRFs, none of these were changed, the drafting team did not ask the question again.

10. The 15% margin is for inherent error in the relay and sensing circuits.

11. This question is outside the scope of the drafting team.

12. There are other standards that require system operators to have facilities and systems in place and operational to operate the system within established system operating limits – and the system operating limits must be set to respect the associated facility ratings.

13. These are the minimum criteria and prudent operation can always exceed them.

14. This concern appears to only be related to MHO relays and could be alleviated with the use of more modern relay technology.

15. Please see R 1.13.

16. The standard is tied to the Facility Ratings independent of the operating condition.

17. See Requirement 1.12 for the 125% setting requirements and appropriately modify the facility ratings.