The Relay Loadability Standard Drafting Team thanks all commenters who submitted comments on the 1st of the Relay Loadability standard. This standard was posted for a 45-day public comment period from August 16 through September 29, 2006. The Relay Loadability Standard Drafting Team asked stakeholders to provide feedback on the standard through a special standard Comment Form. There were 36 sets of comments, including comments from more than 100 different people from more than 50 companies representing 6 of the 9 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team is posting this standard for another comment period.

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 standard can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Relay-Loadability.html

## Summary of Major Changes:

- Most stakeholders who submitted comments on the proposed standard agree that the requirements stated in this standard accurately address the industry action generally referred to as the "NERC Recommendation 8a Review" and the "Protection System Review Program – Beyond Zone 3". Stakeholders are also in general agreement that the Reference Document should be made available as a voluntary reference and as a result the reference document will be listed in the standard as a reference but will not be made a part of the standard.
- Added the Reliability Coordinator as a responsible entity and added a requirement for the Reliability Coordinator to determine which of the facilities within its Reliability Coordinator Area are critical to the reliability of the Bulk Electric System.
- Made the following technical clarifications based on stakeholder comments:
    - Modified R1 by adding the phrase, "for any specific circuit terminal" to add more definition to the scope of the requirement.
    - Modified R1.3 to clarify that, when setting transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability, entities must use a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance of the circuit.
    - Modified R1.3.2 to clarify that it is not the 'per unit bus voltage at each end of the line' that should be used when performing the power transfer calculation, but the 'per unit voltage behind each source impedance' that should be used.
    - Modified the scope of R1.10 to add transmission line relays on transmission lines terminated only with a transformer
    - Modified R1.12 to add the parenthetical phrase shown as follows:

        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 . . .

- Modified Requirement 2 to clarify that the responsible entity must obtain, 'agreement from its Planning Authority, Transmission Operator and Reliability Coordinator' rather than 'approval of its Regional Reliability Organization and Reliability Coordinator' prior to using the criteria in R1.6, etc.
- Modified the Attachment to clarify that overload protection with a fifteen minute or longer response time is excluded from this standard.
- Modified the Attachment to clarify that out-of-step blocking schemes must be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements.
- Modified the Attachment to clarify that relay elements associated with DC lines and relay elements associated with transformers at converter stations are covered by this standard.

▪ No significant regional differences or conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement were identified.

▪ Many of the stakeholders did not agree with the effective dates of the standard and these were changed to bring them into conformance with the format requested by the Compliance Program and to reflect that the effective dates are linked to the approvals from applicable regulatory authorities. If entities conformed to the relay loadability review and mitigation activities directed by the Planning Committee through the System Protection and Control Task Force (as reported via the Regions), they should be in compliance with this proposed standard upon completion of the timetable for those activities. The drafting team did include, in the implementation plan and the revised effective dates, language to indicate that approved requests for Temporary Exceptions that have already been approved by the Planning Committee will be translated and respected. Note that for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, entities have at least 39 months following applicable regulatory approvals to become compliant.

▪ A number of stakeholders indicated that they feel the violation risk factors are too high, but most agreed with the proposed risk factors and with the exception of the rating for R2, the violation risk factors were not changed. The rating for R2 was changed from lower to medium, to align with the changes made to the requirement based on stakeholder feedback.

▪ A new version of the *Reliability Standards Development Procedure Manual* was approved by the NERC Board of Trustees on November 1, 2006. The drafting team made the following changes to the standard to bring it into conformance with the revised manual or to conform to the ERO Rules of Procedure:

– **Mitigation Time Horizons**
The ERO Rules of Procedure include the use of Mitigation Time Horizons as one element used to determine the size of sanctions. The drafting team used the following guidelines in developing mitigation time horizons for each requirement:
  - ***Long-term Planning:*** a planning horizon of one year or longer.
  - ***Operations Planning****:* operating and resource plans from day-ahead up to and including seasonal.
  - ***Same-day Operations****:* routine actions required within the timeframe of a day, but not real-time.
  - ***Real-time Operations****:* actions required within one hour or less to preserve the reliability of the bulk electric system.
  - ***Operations Assessment***: follow-up evaluations and reporting of real time operations.

- **Levels of Non-compliance Versus Violation Severity Levels**

  The drafting team deleted 'levels of non-compliance' and added 'violation severity levels' to comply with the revised Reliability Standard Development Procedure Manual. Compliance personnel assisted the drafting team in using the following criteria from the manual to establish violation severity levels:

  - ***Lower:*** mostly compliant with minor exceptions — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more minor details. Equivalent score: 95% to 99% compliant.
  - ***Moderate:*** mostly compliant with significant exceptions — the responsible entity is mostly compliant with and meets the intent of the requirement but is deficient with respect to one or more significant elements. Equivalent score: 85% to 94% compliant.
  - ***High:*** marginal performance or results — the responsible entity has only partially achieved the reliability objective of the requirement and is missing one or more significant elements. Equivalent score: 70% to 84% compliant.
  - ***Severe:*** poor performance or results — the responsible entity has failed to meet the reliability objective of the requirement. Equivalent score: less than 70% compliant.

- **Associated Documents**

  The drafting team added a section 'F' to the standard called, 'Associated Documents' to list items such as forms, related standards, reports, etc.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Cauley at 609-452-8060 or at gerry.cauley@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 | Company | Industry Segment | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
| John F. Bussman | AECI | ✓ | | | | | | | | |
| James H. Sorrels, Jr. | AEP | ✓ | | | | ✓ | ✓ | | | |
| Anita Lee | AESO | | ✓ | | | | | | | |
| Ken Goldsmith | ALT | | ✓ | | | | | | | |
| Robert Rauschenbach | Ameren | ✓ | | | | | | | | |
| Mike McDonald (NERC SPCTF) | Ameren | | | | | | | | | |
| Henry Miller (NERC SPCTF) | American Electric Power | | | | | | | | | |
| Mike Gentry (WECC RCWG) | APS | | ✓ | | | | | | | |
| Baj Agrawal (NERC SPCTF) | Arizona Public Service | | | | | | | | | |
| Dave Rudolph | BEPC | | ✓ | | | | | | | |
| Lorissa Jones | BPA Transmission | ✓ | | | | | | | | |
| Dean Bender | BPA Transmission | ✓ | | | | | | | | |
| Brenda Coopernoll | BPA Transmission | ✓ | | | | | | | | |
| Jon Duame | BPA Transmission | ✓ | | | | | | | | |
| Brent Kingsford | California ISO | | ✓ | | | | | | | |
| Greg Tillitson (WECC RCWG) | CMRC | | ✓ | | | | | | | |
| Ed Thompson (CP9 RSWG) | ConEd | ✓ | | | | | | | | |
| Tom Weidman (NERC SPCTF) | Consultant | | | | | | | | | |
| Richard G. Cottrell | Consumers Energy | | | ✓ | ✓ | | | | | |
| Carl Kingsley | Delmarva Power | ✓ | | | | | | | | |
| Ed Davis | Entergy Services, Inc. | ✓ | | | | | | | | |
| H. Steven Myers | ERCOT | | ✓ | | | | | | | |
| William Miller (NERC SPCTF) | Exelon | | | | | | | | | |
| David Folk | First*Energy* | ✓ | | ✓ | | ✓ | ✓ | | | |
| John E. Odom, Jr. | FRCC | | ✓ | | | | | | | |
| Eric Senkowicz | FRCC | | ✓ | | | | | | | |

| Commenter | Company | Industry Segment | | | | | | | | |
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| Phillip Winston (NERC SPCTF) | Georgia Power Co. | | | | | | | | | |
| Phil Winston | Georgia Power Company | | | ✓ | | | | | | |
| Dick Pursley | GRE | | ✓ | | | | | | | |
| John Ciufo (NERC SPCTF) | Hydro One | | | | | | | | | |
| David Kiguel | Hydro One Networks Inc. | ✓ | | ✓ | | | | | | |
| Dave Angell (NERC SPCTF) | Idaho Power | | | | | | | | | |
| Ron Falsetti | IESO | ✓ | | | | | | | | |
| Bill Shemley (CP9 RSWG) | ISO New England | | ✓ | | | | | | | |
| Charles Yeung – SPP | ISO/RTO Council | | ✓ | | | | | | | |
| Thomas Bowe – PJM | ISO/RTO Council | | ✓ | | | | | | | |
| Peter Brandien – ISO-NE | ISO/RTO Council | | ✓ | | | | | | | |
| Michael Calimano – NYISO | ISO/RTO Council | | ✓ | | | | | | | |
| John Dumas – ERCOT | ISO/RTO Council | | ✓ | | | | | | | |
| Ron Falsetti – IESO | ISO/RTO Council | | ✓ | | | | | | | |
| Roger Champagne | Hydro-Québec TransÉnergie | ✓ | | | | | | | | |
| Brent Kingsford – CAISO | ISO/RTO Council | | ✓ | | | | | | | |
| Anita Lee – AESO | ISO/RTO Council | | ✓ | | | | | | | |
| Bill Phillips – MISO | ISO/RTO Council | | ✓ | | | | | | | |
| Jim Cyrulewski | JDRJC | ✓ | | | | | | | | |
| Eric Ruskamp | LES | | ✓ | | | | | | | |
| Robert Coish (NERC SPCTF) | Manitoba Hydro | | | ✓ | | ✓ | ✓ | | | |
| Don Nelson (CP9 RSWG) | Mass. Dept. of Tele. and Energy | | | | | | | | | ✓ |
| Tom Mielnik | MEC | | ✓ | | | | | | | |
| Tim Bartel | Minnkota Power Coop | | | | | | | | | |
| Terry Bilke | MISO | | ✓ | | | | | | | |
| Don Raveling | Montana-Dakota Utilities | ✓ | | | | | | | | |

| Commenter | Company | Industry Segment | | | | | | | | |
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| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
| Carol Gerou | MP | | ✓ | | | | | | | |
| Larry E. Brusseau | MRO | | ✓ | | | | | | | |
| Joseph Knight | MRO | | ✓ | | | | | | | |
| Herb Schrayshuen | National Grid | ✓ | | | | | | | | |
| Phillip Tatro (NERC SPCTF) | National Grid USA | | | | | | | | | |
| Robert Cummings (NERC SPCTF) | NERC | | | | | | | | | |
| David Taylor | NERC | | | | | | | | | |
| Jim Ingleson (CP9 RSWG) | New York ISO | | ✓ | | | | | | | |
| Ralph Rufrano (CP9 RSWG) | New York Power Authority | ✓ | | | | | | | | |
| Al Adamson (CP9 RSWG) | New York State Relia. Council | | ✓ | | | | | | | |
| Mike Gopinathan (CP9 RSWG) | Northeast Utilities | ✓ | | | | | | | | |
| Guy V. Zito (CP9 RSWG) | NPCC | | ✓ | | | | | | | |
| Guy V. Zito | NPCC | | ✓ | | | | | | | |
| Al Boesch | NPPC | | ✓ | | | | | | | |
| Michael Calimano | NYISO | | ✓ | | | | | | | |
| Mark Ringhausen | Old Dominion Electric Coop. | | | | ✓ | | | | | |
| Todd Gosnell | OPPD | | ✓ | | | | | | | |
| Alvin Depew | Pepco | ✓ | | | | | | | | |
| Evan Sage | Pepco | ✓ | | | | | | | | |
| Richard Kafka | Pepco Holdings, Inc. | ✓ | | | | | | | | |
| Joe Burdis (NERC SPCTF) | PJM | | | | | | | | | |
| Al DiCaprio | PJM Reliability Services Division | | ✓ | | | | | | | |
| Mark Kuras | PJM Reliability Services Division | | ✓ | | | | | | | |
| Robert Thomas | PJM Reliability Services Division | | ✓ | | | | | | | |
| Joe Burdis | PJM Reliability Services | | ✓ | | | | | | | |

| Commenter | Company | Industry Segment | | | | | | | | |
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| | Division | | | | | | | | | |
| D. Bryan Guy | Progress Energy – Carolinas | ✓ | | ✓ | | ✓ | | | | |
| Steve Johnson (WECC RCWG) | RDRC | | ✓ | | | | | | | |
| Frank McElvain (WECC RCWG) | RDRC | | ✓ | | | | | | | |
| Robert W. Millard | RFC | | ✓ | | | | | | | |
| Jon Sykes (NERC SPCTF) | Salt River Project | | | | | | | | | |
| Neil Shockey | SCE | ✓ | | | | | | | | |
| Bridget Coffman (SCPSA) | SERC Protection & Control Subc. | ✓ | | | | | | | | |
| Susan Morris (SERC RO) | SERC Protection & Control Subc. | | ✓ | | | | | | | |
| Phil Winston (Georgia Power) | SERC Protection & Control Subc. | ✓ | | | | | | | | |
| Ernesto Paon (MEAG) | SERC Protection & Control Subc. | ✓ | | | | | | | | |
| Sonia Walden (DOM VA Power) | SERC Protection & Control Subc. | ✓ | | | | | | | | |
| Marion Frick (SC&EG) | SERC Protection & Control Subc. | ✓ | | | | | | | | |
| Steve Waldrep (Georgia Power) | SERC Protection & Control Subc. | ✓ | | | | | | | | |
| Charlie Fink (Entergy) | SERC Protection & Control Subc. | ✓ | | | | | | | | |
| Paul Smith (Duke – Carolinas) | SERC Protection & Control Subc. | ✓ | | | | | | | | |
| Jay Farrington (Al. Elec. Coop) | SERC Protection & Control Subc. | ✓ | | | | | | | | |
| George Pitts (TVA) | SERC Protection & Control Subc. | ✓ | | | | | | | | |
| Robert Rauschenbach (Ameren) | SERC Protection & Control | ✓ | | | | | | | | |

| Commenter | Company | Industry Segment | | | | | | | | |
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| | Subc. | | | | | | | | | |
| Hong Ming Shuh (GA Trans. Corp.) | SERC Protection & Control Subc. | ✓ | | | | | | | | |
| Patrick Huntley | SERC RC | | ✓ | | | | | | | |
| Jim Busbin | So. Company Services, Inc. | ✓ | | | | | | | | |
| J.T. Wood | So. Company Services, Inc. | ✓ | | | | | | | | |
| Roman Carter | So. Company Services, Inc. | ✓ | | | | | | | | |
| Nancy Wofford (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Lee Xanthakos (SCE&G ERO WG) | South Carolina Electric & Gas | ✓ | | | | | | | | |
| Hubert C. Young (SCE&G ERO WG) | South Carolina Electric & Gas | | | ✓ | | | | | | |
| Richard Jones (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | ✓ | | | | |
| Henry Delk (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| John T. Blalock (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Dan Goldston (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Todd Johnson (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Jay Hammond (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Pat Longshore (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Simon Shealy (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Bob Smith (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Andy Bowden (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Arnie Cribb (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Marion Frick (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Jerry Lindler (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Wayne Stuart (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Brad Stokes (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Shawn McCarthy (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Ernie Mehaffey (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |

| Commenter | Company | Industry Segment | | | | | | | | |
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| | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
| Rick Lytle (SCE&G ERO WG) | South Carolina Electric & Gas | | | | | | | | | |
| Neil Shockey | Southern California Edison | ✓ | | | | | | | | |
| Terry Crawley | Southern Nuclear | | | | | ✓ | | | | |
| Wayne Guttormson | SPC | | ✓ | | | | | | | |
| Mark Nagle | SPP | | ✓ | | | | | | | |
| Makarand Nagle | SPP | | ✓ | | | | | | | |
| Roger Champagne (CP9 RSWG) | TransÉnergie Hydro-Québec | ✓ | | | | | | | | |
| John D. Roberts (NERC SPCTF) | TVA | | | | | | | | | |
| Nancy Bellows (WECC RCWG) | WAPA | | ✓ | | | | | | | |
| Deven Bhan (NERC SPCTF) | WAPA | | | | | | | | | |
| Darrick Moe | WAPA | | ✓ | | | | | | | |
| Kenneth J. Wilson | WECC | | ✓ | | | | | | | |
| Jim Maenner | WPS | | ✓ | | | | | | | |
| Pam Oreschnick | XEL | | ✓ | | | | | | | |

## Index to Questions, Comments and Responses

1. **Do you feel that the requirements stated in this standard accurately address the industry action generally referred to as the "NERC Recommendation 8a Review" and the "Protection System Review Program – Beyond Zone 3".**

Recommendation 8a called for all transmission owners to evaluate the zone 3 relay settings on all transmission lines operating at 230 kV and above for the purpose of verifying that each zone 3 relay is not set to trip on load under extreme emergency conditions. These activities included a review of all transmission protection systems relative to provided criteria and correction of those systems that did not conform to the criteria. The criteria established for those review activities are the genesis of this standard.

**Summary Consideration:** Most stakeholders agree that the requirements stated in this standard accurately address the industry action generally referred to as the "NERC Recommendation 8a Review" and the "Protection System Review Program – Beyond Zone 3". There were several suggestions for minor edits and changes. The drafting team made the following changes to the standard based on stakeholder comments:

- Added the Reliability Coordinator as a responsible entity and added a requirement for the Reliability Coordinator to determine facilities critical to the reliability of the electric system.
- Modified the Attachment to indicate that overload protection with a fifteen minute or longer response time is excluded from this standard
- Modified the Attachment to clarify that out-of-step blocking schemes must be evaluated to ensure that they do not block trip for faults during the loading conditions defined within the requirements

| Question #1 – Do requirements address Recommendation 8a and Protection System Review Program – Beyond Zone 3? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| MRO (2) et al<br>Joseph Knight<br><br>Manitoba Hydro (3, 5, 6)<br>Robert Coish | | | The MRO (Manitoba Hydro) generally believes this standard addresses the industry action listed above but has some significant reservations about how the standard is written as well as concerns about potential risks to reliability if this standard is implemented.<br><br>1) This standard should be more directly based on the concept that collapse should be slowed or delayed to the extent of the thermal capability of facilities. Suggest the purpose statement read - Protective relay settings shall not limit transmission loadability uncontrolled collapse is slowed or delayed to the extent of the thermal capability of facilities. The proposed standard should make direct reference to the additional time this standard is targeting to give the operators to respond to an emergency situation. In the current draft there is a rather indirect reference to 15 minutes.<br><br>(2) The MRO (Manitoba Hydro) s 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 (Manitoba Hydro) believes there is increased inhent 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 |

| Question #1 – Do requirements address Recommendation 8a and Protection System Review Program – Beyond Zone 3? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | 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 (Manitoba Hydro) believes that a risk analysis should be conducted before implementing this standard.<br><br>(3) The MRO (Manitoba Hydro) believes this draft of the standard is too prescriptive. The equipment owner should be deciding the appropriate level of risk with rgard 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.<br><br>(4) The SAR designates that this standard shall also be applicable to the Regional Reliability Organization. In its response to comments the SAR drafting team stated - It is anticipated that the RRO will be responsible for compliance to NERC for developing a methodology for identifying its operationally significant circuits and for identification of those operationally significant circuits. The SAR was modified to include these clarifications. - However, there are no requirements on the RRO in this standard. Specifically, where in the standards is the RRO required to identify lines/transformers critical to the reliability of the electric system? If it is even appropriate for the RRO to come up with the methodology, the needed requirements on the RRO should include a requirement to develop the methodology in coordination with the RC, PA and the TO.<br><br>(5) In 4.1.2 and 4.1.4, the words "as designated by the Regional Reliability Organization as critical to the reliability of the electric system" are not consistent with those used in the SAR (operationally significant circuits, etc.).<br><br>(6) 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 wavetraps 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? |
| Response:<br>(1) The required operator response is defined in TOP-008 and it is inappropriate to repeat this requirement in this standard. Overload protection with a fifteen minute or longer response time has been added to the protection systems excluded from this standard, in Attachment A.<br>System protection systems must balance security and dependability. Security means not tripping when you do not want to; dependability means tripping when you want to trip. Numerous companies have provided input to this standard. Some companies lean more towards security some lean more towards dependability. This standard represents an acceptable balance between the two. | | | |

| Question #1 – Do requirements address Recommendation 8a and Protection System Review Program – Beyond Zone 3? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| (2) System protection systems are designed to remove faults. Typically, system protection criteria do not include preventing equipment damage from overload conditions. Operator action is required to protect facilities from overload conditions per NERC Standard TOP-008-0, R3. If facility overload protection is desired, it should be provided by protective elements designed and applied expressly for overload protection incorporating appropriate time delays which permit the operator time to respond.<br>(3) Most stakeholders who responded seem to indicate support for this detail.<br>(4) The standard has been changed to assign a requirement to the Reliability Coordinator for this function.<br>(5) The Drafting Team revised these requirements to assign responsibility to the Reliability Coordinator; the language used in the standard has the same meaning as that in the SAR.<br>(6) Other NERC standards require facility ratings be defined and that the system be operated within those ratings. | | | |
| WECC Reliability Coordination Working Group<br>Nancy Bellows – WAPA (2) | | ☑ | See Comment # 7. RCCWG does not feel that this standard accurately addresses the Industry action due to the concerns stated. That said, to the extent that extreme emergency conditions can be identified in advance of their occurrence and simulated, this standard has addressed the stated concerns. |
| Response: See Drafting Team's response to your comment on question 7. | | | |
| Ameren (1)<br>Robert Rauschenbach | | ☑ | A more straight forward standard should be developed where the NERC formula is used for Relay Load Limit Calculations for 230 kV and above. The Relay Load Limit would then need to be used by Operations and Planning as a line limit not to be exceeded under the NERC Table 1 conditions. The conservative 0.85 per unit voltage and 1.5 current values used in the NERC formula would provide margin against relay trips under multiple contingencies / extreme emergencies.<br><br>This method would be more performance based and less prescriptive. It avoids the exceptions and their various interpretations, and allows utilities to set relays as needed to best provide a reliable system. Requiring the Relay Load Limit to exceed the maximum thermal rating does not make sense if the thermal capacity is not being used, but merely available for ultimate designs. The requirement to exceed maximum thermal rating is what ultimately leads to the need for exceptions and their interpretation.<br><br>A utility attempting to meet this standard may be providing less backup coverage when it is not necessary. This lack of backup could ultimately lead to reduced reliability or a blackout scenario due to an un-cleared fault on the system. |
| Response: Table 1 does not apply. This standard addresses conditions beyond Table 1 category C. System protection systems must balance security and dependability. Security means not tripping when you do not want to; dependability means tripping when you want to trip. Numerous companies have provided input to this standard. Some companies lean more towards security some lean more towards dependability. This standard represents an acceptable balance between the two. R1.2 – R1.13 are provided to specify rating conditions other than thermal which the relay loadability must address; use of these requirements allows maximum backup coverage. This standard requires that reliable protection | | | |

| Question #1 – Do requirements address Recommendation 8a and Protection System Review Program – Beyond Zone 3? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| be provided while allowing transmission loadability. | | | |
| Consumers Energy (3, 4)<br>Richard G. Cottrell | ☑ | | The referenced activities seem to be all included in the requirements, but nothing additional seems to be included. However, the supporting information in the documents for the previous activities seems crucial to being able to meet the requirements |
| Response: The Reference Document and perhaps other documents will be provided as supporting material but will not be part of the standard. | | | |
| NERC System Protection and Control Task Force<br>Jon Sykes | ☑ | | PRC-023 (Draft), in Appendix A, briefly mentions Switch-onto-Fault relaying and Out-of-Step Blocking and Tripping relaying, but very little else is said about these subjects, either in the Standard or in the Reference Paper. The above-referenced previous actions addressed these subjects in detail; SOTF is the subject of an informational paper by the SPCTF. We recommend that these subjects be addressed in more detail, particularly in the Reference Document. |
| Response: Two appendices (Appendix C — Out-of-step Blocking Relaying and Appendix D – Switch-on-to-Fault Scheme) have been added to the PRC-023 Reference Document to address your concerns. | | | |
| AECI (1)<br>John F. Bussman | ☑ | | Basically they do, however AECI does not believe that .85 pu for calculations is necessary. Our standards used 1.0 pu. |
| Response: The industry actions relate relay loadability to system collapse. Therefore the use of 0.85 pu voltage for relay performance calculations is appropriate. Studies into the various WECC collapses, into the 1967 blackout, and into August 2003 show that the system voltage becomes depressed during the pre-collapse time periods, and it is these time periods during which the evaluation of the relay performance is most critical. | | | |
| Pepco Holdings, Inc. Affil. (1)<br>Richard Kafka | ☑ | | PHI supports the complete set of comments of the NERC System Protection and Control Task Force (SPCTF) for this standard. We will not repeat them in our comments. |
| Response: Acknowledged. Please see the responses to the SPCTF comments. | | | |
| Montana-Dakota Utilities (1)<br>Don Raveling | ☑ | | |
| First*Energy* (1, 3, 5, 6)<br>David Folk | ☑ | | |
| Entergy Services, Inc. (1)<br>Ed Davis | ☑ | | |
| NPCC CP9 Reliability Standards Working Group<br>Guy Zito – NPCC (2) | ☑ | | |
| Hydro One Networks Inc. | ☑ | | |

| Question #1 – Do requirements address Recommendation 8a and Protection System Review Program – Beyond Zone 3? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| (1, 3) – David Kiguel | | | |
| IESO (2)<br>Ron Falsetti | ☑ | | |
| AEP ( 1, 5, 6)<br>James H. Sorrels, Jr. | ☑ | | |
| JDRJC Associates (1)<br>Jim Cyrulewski | ☑ | | |
| Old Dominion Electric Coop. (4) – Mark Ringhausen | ☑ | | |
| So. California Edison (1)<br>Neil Shockey | ☑ | | |
| Progress Energy– Carolinas (1, 3, 5) – D. Bryan Guy | ☑ | | |
| SCE&G ERO Working Group<br>Sally Wofford | ☑ | | |
| BPA Transmission (1)<br>Lorissa Jones | ☑ | | |
| National Grid (1)<br>Herb Schrayshuen | ☑ | | |
| PJM Reliability Services Division – Al DiCaprio (2) | ☑ | | |
| ISO/RTO Council<br>Charles Yeung | ☑ | | |
| AESO (2)<br>Anita Lee | ☑ | | |
| FRCC (2)<br>Eric Senkowicz | ☑ | | |
| New York ISO (2) | ☑ | | |

| Question #1 – Do requirements address Recommendation 8a and Protection System Review Program – Beyond Zone 3? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Michael Calimano | | | |
| So. Company Services, Inc. (1) – Jim Busbin | ☑ | | |
| SCE (1)<br>Neil Shockey | ☑ | | |
| Hydro-Québec TransÉnergie (1) – Roger Champagne | ☑ | | |
| SERC PCS<br>Susan Morris | ☑ | | |

2. **Do you believe the Transmission Relay Loadability Standard Reference Document should be incorporated as an 'Attachment' to the standard and made mandatory or provided as a 'Voluntary Reference' outside the standard to support implementing the standard? Explain why.**

☐ Reference should be made a mandatory part of the standard.

☐ Reference should be made available as a voluntary reference without mandatory compliance.

**Summary Consideration:** Almost all stakeholders agree that the Reference Document should be made available a as a voluntary reference. As a result the reference document will be listed in the standard as a reference but will not be made a part of the standard.
The drafting team made the following conforming changes to the standard, based on stakeholder comments:

- Modified R1.3 to clarify that, when setting transmission line relays so they do not operate at or below 115% of the maximum theoretical power transfer capability, entities must use a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance of the circuit.
- Modified R1.3.2 to clarify that it is not the 'per unit bus voltage at each end of the line' that should be used when performing the power transfer calculation, but the per unit voltage behind each source impedance that should be used.
- Modified R1.12 to add the parenthetical phrase shown as follows:
  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:

| Question #2 – Should reference document be a mandatory part of the standard or a voluntary reference? | |
|---|---|
| **Commenter** | **Comment** |
| Montana-Dakota Utilities (1)<br>Don Raveling | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br>The reference provides additional explanations for the standard. It may be possible to comply with the standard without compliance to the reference, although I don't know how that would be done. To me this doesn't matter too much, but it perhaps would to a lawyer. What about the other reference documents on "out-of-step" and "3-terminal lines"? Would they be left as reference documents or become part of the standard too? Again they are helpful documents and provide good and helpful information but I think "Reference For Standard PRC-0230-1" is appropriate. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. The drafting team will review other available documents as other "Voluntary Reference Material". | |
| WECC Reliability Coordination Working Group<br>Nancy Bellows – WAPA (2) | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>The RCCWG feels the standard should include all requirements. The reference document should remain a document that can be revised without requiring the standards process be followed. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. | |

| Question #2 – Should reference document be a mandatory part of the standard or a voluntary reference? | |
|---|---|
| **Commenter** | **Comment** |
| First*Energy* (1, 3, 5, 6)<br>David Folk | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>Including the reference material with all of its technical exceptions into the standard would be confusing since the exceptions are similar to the standard's requirements but worded differently. However, attaching the non-mandatory reference material would serve as a historical record of development of the standard and may enhance the understanding of the standard. If future developments call for changes to the standards criteria, making the reference voluntary will allow it to remain as a background document. In addition, a citing for this reference material is needed in the standard. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. A citation within the standard will be provided. | |
| Entergy Services, Inc. (1)<br>Ed Davis | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br>Due to the technical complexities of the standard, the reference document is useful for providing guidance to achieve compliance. Although the document addresses the specific requirements and could possibly be used to determine compliance, it may not be all encompassing. It should not be used as a basis for determining any non-compliance and therefore should not be part of the standard. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. | |
| NPCC CP9 Reliability Standards Working Group<br>Guy Zito – NPCC (2)<br><br>New York ISO (2)<br>Michael Calimano | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>The maintenance of the reference manual is preferred. As we go forward the SPCTF or similar can make changes/revisions without going through the NERC Process each time. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. | |
| IESO (2)<br>Ron Falsetti | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>The maintenance of the reference manual is preferred. As we go forward the SPCTF or similar can make changes/revisions without going through the NERC Process each time. Should it be determined that aspects of the reference manual need to be mandatory and not a guideline they need to be incorporated into the standard. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. | |
| Hydro-Québec TransÉnergie | ☑Reference should be made available as a **voluntary reference** without mandatory compliance. |

| Question #2 – Should reference document be a mandatory part of the standard or a voluntary reference? | |
|---|---|
| **Commenter** | **Comment** |
| (1) – Roger Champagne | The maintenance of the reference manual is preferred. As we go forward the SPCTF or similar can make changes/revisions without going through the NERC Process each time. That document should be referenced somewhere in the standard. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. | |
| AEP ( 1, 5, 6)<br>James H. Sorrels, Jr. | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>The Reference material provides example calculations of how to accomplish the requirements included in the Loadability Standard. The Reference guide may need updated from time to time to stay current as an aid without the standard needing to be updated. The reference material does not add any requirements, it only explans how to meet the requirements contained in the Loadability Standard. Therfore, Reference Document should remain a separate document, but should be clearly referenced within the Loadability Standard so that it can be found and used to meet the Loadability Standard requirements. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. | |
| JDRJC Associates (1)<br>Jim Cyrulewski | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>Anything in the reference that should be mandatory shouled be included in the standards requriements not in an attachment. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. | |
| Progress Energy–Carolinas (1, 3, 5) – D. Bryan Guy | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>PEC believes the reference document separate but referenced in the standard making it available to easily correct if necessary. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. | |
| Consumers Energy (3, 4)<br>Richard G. Cottrell | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>It seems to be very difficult, if not impossible, to accurately apply the Standard without the Reference Document, but the Reference Document should be available such that it can be easily corrected if necessary. In order to support the tie between the Standard and the Reference Document, it seems that the Reference |

| Question #2 – Should reference document be a mandatory part of the standard or a voluntary reference? | |
|---|---|
| **Commenter** | **Comment** |
| | Document should be referenced within the standard, either via a statement within R1 such as "For additional guidance on these requirements, please see "PRC-023 Reference - Determination and Application of Practical Relaying Loadability Ratings", or via a similar footnoted reference on R1. |
| Response: The Reference Document will be provided as a “Voluntary Reference” outside the standard to support implementing the standard, per industry consensus. A citation within the standard will be provided. | |
| SCE&G ERO Working Group<br>Sally Wofford | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>Without the reference document, it will be very difficult to accurately apply the standard. At the minimum, the Standard should clearly provide reference to Reference Document. The following question should be asked: Will auditors judge compliance with the Standard by applying the Reference Document? If so, maybe the Reference Document should be included in the standard. The only reason this commenter did not check the other box (reference part of the standard) is to avoid encumbering clarification/correction of the reference document when needed. |
| Response: The Reference Document will be provided as a “Voluntary Reference” outside the standard to support implementing the standard, per industry consensus. A citation within the standard will be provided. | |
| NERC System Protection and Control Task Force<br>Jon Sykes<br><br>SERC PCS<br>Susan Morris | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>It will be very difficult, if not impossible, to accurately apply the Standard without the Reference Document, but the Reference Document should be available to easily correct if necessary. However, the Standard should, either within a footnote or as a direct reference within the Standard itself, call the user's attention to the existence of the Reference Document and the Reference should be posted with the Standard on the NERC Standards website. |
| Response: The Reference Document will be provided as a “Voluntary Reference” outside the standard to support implementing the standard, per industry consensus. A citation within the standard will be provided. | |
| National Grid (1)<br>Herb Schrayshuen | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>The entire Reference Document should not be incorporated in the standard; however, the standard Drafting Team should review the draft standard to ensure that adequate information is contained in each Requirement to ensure consistent interpretation and application. In some cases important information necessary to apply the stated Requirement is contained in text or a diagram within the Reference standard. Some examples that we find requiring further clarification include:<br>R1.3: Additional information is required regarding line resistance and the power angle between the sending and receiving line terminals.<br>R1.3.2: The reference to 1.05 p.u. voltage should identify this as the Thevenin equivalent source voltage |

<table>
<tr><th colspan="2">Question #2 – Should reference document be a mandatory part of the standard or a voluntary reference?</th></tr>
<tr><th>Commenter</th><th>Comment</th></tr>
<tr><td></td><td>behind the actual system source impedance at each end of the line, rather than at the end of the line.<br>R1.12: The maximum distance relay setting should clarify that the reach at the maximum torque angle (MTA) shall be set to provide no greater than 125% overreach at the impedance angle of the protected transmission line. The present language could be interpreted as requiring a setting of no more 125% of the line impedance magnitude applied at the MTA, which may not provide adequate protection coverage at the line impedance angle.<br>The Reference Document contains a significant volume of information to assist the industry in applying the standard. Additional information as noted above should be included in the standard, and the remaining information in the Reference Document should be posted with the standard on the NERC website as a separate reference source.</td></tr>
<tr><td colspan="2">Response: The Reference Document will be provided as a “Voluntary Reference” outside the standard to support implementing the standard, per industry consensus. A citation within the standard will be provided.<br>R1.3 was modified to add more information to clarify that entities must use a 90-degree angle between the sending-end and receiving-end voltages and either reactance or complex impedance of the circuit<br>R1.3.2 was modified as suggested and now states:<br>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.<br>R1.12 was modified to add the parenthetical phrase shown as follows:<br>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:</td></tr>
<tr><td>PJM Reliability Services Division – Al DiCaprio (2)</td><td>☑Reference should be made available as a voluntary reference without mandatory compliance.<br>PJM supports the separation of standards (i.e. mandatory requirements and measures) from Guidelines and Technical Documents.</td></tr>
<tr><td colspan="2">Response: The Reference Document will be provided as a “Voluntary Reference” outside the standard to support implementing the standard, per industry consensus.</td></tr>
<tr><td>AESO (2)<br>Anita Lee<br><br>ISO/RTO Council<br>Charles Yeung</td><td>☑Reference should be made available as a voluntary reference without mandatory compliance.<br>The AESO (IRC) supports the separation of standards (i.e. mandatory requirements and measures) from Guidelines and Technical Documents. Unless the material in the Technical Requirement is required, then the Reference Document should be kept separate from the standard.</td></tr>
<tr><td colspan="2">Response: The Reference Document will be provided as a “Voluntary Reference” outside the standard to support implementing the standard, per industry consensus.</td></tr>
</table>

| Question #2 – Should reference document be a mandatory part of the standard or a voluntary reference? | |
|---|---|
| **Commenter** | **Comment** |
| FRCC (2)<br>Eric Senkowicz | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>The reference document should be made "voluntary" in order to preserve and maintain the clarity of the requirements within the standard. The current compliance programs are not designed to interpret and measure reference documents and therefore would make compliance enforcement to another "type" of document inappropriate, difficult and confusing, especially with regard to the technical nature of the content. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. | |
| So. Company Services, Inc. (1) – Jim Busbin | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>Southern Company Transmission agrees with the explanation for this selection made by the SERC Protection and Control Subcommittee and the NERC System Protection and Control Task Force. Their explanations state, "It will be very difficult, if not impossible, to accurately apply the Standard without the Reference Document, but the Reference Document should be available to easily correct if necessary. However, the Standard should, either within a footnote or as a direct reference within the standard itself, call the user's attention to the existence of the Reference Document and the Reference should be posted with the Standard on the NERC Standards website." |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. A citation within the standard will be provided. | |
| Manitoba Hydro (3, 5, 6)<br>Robert Coish | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>In its response to comments the SAR drafting team stated that - the resulting standard to be developed will develop loadability requirements, not methods to satisfy the requirements -. Manitoba Hydro agrees with this approach of the SAR drafting team. The reference document should not be made part of the standard because the how should be left up to the owner of the protection system. Also, a reference document will not be able to keep up to date with changing relay technology. Manitoba Hydro recognizes the value of the reference document as a guide and the hard work that went into preparing it. |
| Response: The Reference Document will be provided as a "Voluntary Reference" outside the standard to support implementing the standard, per industry consensus. | |
| MRO (2) et al<br>Joseph Knight | ☑Reference should be made available as a **voluntary reference** without mandatory compliance.<br><br>(1)In its response to comments the SAR drafting team stated that<br>- the resulting standard to be developed will develop loadability requirements, not methods to satisfy the requirements -. The MRO agrees with this approach of the SAR drafting team. The reference document should |

| Question #2 – Should reference document be a mandatory part of the standard or a voluntary reference? | |
|---|---|
| **Commenter** | **Comment** |
| | not be made part of the standard because the how should be left up to the owner of the protection system. Also, a reference document will not be able to keep up to date with changing relay technology. The MRO recognizes the value of the reference document as a guide and the hard work that went into preparing it.<br><br>(2) The reference document (Determination and Application of Practical Relaying Loadability Ratings, Version 1.0,August 14,2006) states generator protection relays are excluded from requirements of this PRC-023-1 standard(Page 1,section 2.3,reference document). The attachment A (section 1.2.4) to standard PRC-023-1 states generator protection relays that are susceptible to load are excluded from requirements of this PRC-023-1 standard. Should the attachment A of the standard be consistent with the reference document for the standard?<br><br>(3) The reference document (Determination and Application of Practical Relaying Loadability Ratings, Version 1.0,August 14,2006) states on page 9 states 200% of aggregated generation nameplate capability when the standard lists 230% of aggregated generated nameplate capability. (section R1.6) Why is the standard 230% when its reference document uses 200%?<br><br>(4) The reference document (Determination and Application of Practical Relaying Loadability Ratings, Version 1.0,August 14,2006) states on page 14 “If an overcurrent relay is supervised by either a top oil or simulated winding hot spot element less than 100°C and 140□C respectively, justification for the reduced temperature must be provided.” Where as in the standard (section R.11, last part), the standard states “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 stop temperature.” Shouldn’t the reference document be consistent with the standard? (Where anything less than 100°C and 140□C would have justification associated with it.) |
| Response: (1) The Reference Document will be provided as a “Voluntary Reference” outside the standard to support implementing the standard, per industry consensus. A citation within the standard will be provided.<br>(2) Changes were made to the reference document to correct the inconsistency between Attachment A and the reference document.<br>(3) An additional 115% factor is included in the green highlighted box in the Reference Document (Clause R1.6).<br>(4) Changes have been made to the reference document to make it consistent with the standard. | |
| Pepco Holdings, Inc. Affil. (1)<br>Richard Kafka | ☑Reference should be made available as a **voluntary reference** without mandatory compliance. |
| SCE (1)<br>Neil Shockey | ☑Reference should be made available as a **voluntary reference** without mandatory compliance. |
| Hydro One Networks Inc. (1, | ☑Reference should be made available as a **voluntary reference** without mandatory compliance. |

| Question #2 – Should reference document be a mandatory part of the standard or a voluntary reference? | |
|---|---|
| **Commenter** | **Comment** |
| 3) – David Kiguel | |
| So. California Edison (1)<br>Neil Shockey | ☑Reference should be made available as a **voluntary reference** without mandatory compliance. |
| NERC Regional Reliability Standards Working Group<br>David Taylor | ☑Reference should be made available as a **voluntary reference** without mandatory compliance. |
| Ameren (1)<br>Robert Rauschenbach | ☑ Reference should be made a **mandatory** part of the standard.<br><br>With the way the present standard is written, the reference document is necessary. |
| Response: The Reference Document will be provided as a “Voluntary Reference” outside the standard to support implementing the standard, per industry consensus. A citation within the standard will be provided. Per other comments some requirements have been clarified within the standard to include necessary information. | |
| AECI (1)<br>John F. Bussman | ☑Reference should be made a **mandatory** part of the standard.<br><br>Everyone needs to set their relays with consistency throughout the region. This will ensure that the way the settings are calculated will be the same for all regions. Any change to the reference will require a change to the standard. |
| Response: The Reference Document will be provided as a “Voluntary Reference” outside the standard to support implementing the standard, per industry consensus. A citation within the standard will be provided. Per other comments some requirements have been clarified within the standard to include necessary information. | |
| Old Dominion Electric Coop. (4) – Mark Ringhausen | ☑Reference should be made a **mandatory** part of the standard. |
| Response: The Reference Document will be provided as a “Voluntary Reference” outside the standard to support implementing the standard, per industry consensus. A citation within the standard will be provided. Per other comments some requirements have been clarified within the standard to include necessary information. | |
| BPA Transmission (1)<br>Lorissa Jones | I don't see how you could be in compliance with one and not the other. The reference supplies necessary details and should be an attachment to the standard. |
| Response: The Reference Document will be provided as a “Voluntary Reference” outside the standard to support implementing the standard, per industry consensus. A citation within the standard will be provided. Per other comments some requirements have been clarified within the standard to include necessary information. | |

## 3. Are you aware of any regional differences that would be required as a result of this standard?

**Summary Consideration:** Almost all stakeholders feel there are no regional differences. The two comments from the two stakeholders that feel there are regional differences have been addressed Based on stakeholder comments, the drafting team made the following change to the standard:

- A requirement was added for the Reliability Coordinator to determine critical facilities within its Reliability Coordinator Area.

| Question #3 – Any regional differences? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Ameren (1)<br>Robert Rauschenbach | ☑ | | The definition of 100-200 kV critical facilities is not defined and will lead to differences between regional interpretations. The requirements should be dropped for 100-200 kV. |
| Response: This responsibility has been reassigned from the RRO to the Reliability Coordinator which has the overall operating and planning responsibility for determining critical facilities within its jurisdiction. | | | |
| BPA Transmission (1)<br>Lorissa Jones | ☑ | | It is more difficult to make relays on long transmission lines comply with the standard. The WECC will be impacted more because of the number of long transmission lines in that region. |
| Response: Understood. This difficulty is one of the primary reasons for the diversity of criteria from which to choose. | | | |
| WECC Reliability Coordination Working Group<br>Nancy Bellows – WAPA (2) | | ☑ | There are, however, philosophical differences in the application of relays, even among neighbors. One example is that some entities do not utilize zone 3 relays, and others find zone 3 relaying to be a vital backup component to system protection. |
| Response: Acknowledged. | | | |
| Montana-Dakota Utilities (1)<br>Don Raveling | | ☑ | |
| First*Energy* (1, 3, 5, 6)<br>David Folk | | ☑ | |
| Entergy Services, Inc. (1)<br>Ed Davis | | ☑ | |
| NPCC CP9 Reliability Standards Working Group<br>Guy Zito – NPCC (2) | | ☑ | |
| Hydro One Networks Inc. (1, 3) – David Kiguel | | ☑ | |
| IESO (2) | | ☑ | |

| Question #3 – Any regional differences? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Ron Falsetti | | | |
| AEP ( 1, 5, 6)<br>James H. Sorrels, Jr. | | ☑ | |
| JDRJC Associates (1)<br>Jim Cyrulewski | | ☑ | |
| Old Dominion Electric Coop. (4) – Mark Ringhausen | | ☑ | |
| So. California Edison (1)<br>Neil Shockey | | ☑ | |
| Progress Energy–Carolinas (1, 3, 5) – D. Bryan Guy | | ☑ | |
| Consumers Energy (3, 4)<br>Richard G. Cottrell | | ☑ | |
| SCE&G ERO Working Group<br>Sally Wofford | | ☑ | |
| Manitoba Hydro (3, 5, 6)<br>Robert Coish | | ☑ | |
| NERC System Protection and Control Task Force<br>Jon Sykes | | ☑ | |
| National Grid (1)<br>Herb Schrayshuen | | ☑ | |
| PJM Reliability Services Division – Al DiCaprio (2) | | ☑ | |
| ISO/RTO Council<br>Charles Yeung | | ☑ | |
| AESO (2)<br>Anita Lee | | ☑ | |
| FRCC (2)<br>Eric Senkowicz | | ☑ | |

| Question #3 – Any regional differences? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| New York ISO (2)<br>Michael Calimano | | ☑ | |
| So. Company Services, Inc. (1) – Jim Busbin | | ☑ | |
| AECI (1)<br>John F. Bussman | | ☑ | |
| MRO (2) et al<br>Joseph Knight | | ☑ | |
| Pepco Holdings, Inc. Affil. (1)<br>Richard Kafka | | ☑ | |
| SCE (1)<br>Neil Shockey | | ☑ | |
| Hydro-Québec TransÉnergie (1) – Roger Champagne | | ☑ | |
| SERC PCS<br>Susan Morris | | ☑ | |

4. **Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement?**

**Summary Consideration:** Almost all stakeholders feel there are no conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement.
Based on stakeholder comments, the drafting team modified Requirement 2 in the standard to clarify that the responsible entity must obtain, 'agreement from its Planning Authority, Transmission Operator and Reliability Coordinator' rather than 'approval of its Regional Reliability Organization and Reliability Coordinator' prior to using the criteria in R1.6, etc. The drafting team added a sub-requirement to clarify that the responsible entity that uses the calculated circuit capability to meet the requirements in this standard must use the same calculated circuit capability as the Facility Rating of the circuit.

| Question #4 – Any conflicts with regulatory functions, etc.? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| NERC Regional Reliability Standards Working Group<br>David Taylor | ☑ | | R2 of this draft standard requires the TO, GO, or DP to obtain approval from the RRO and RC prior to using the criteria established in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 for each circuit terminal using the listed criteria. By establishing an obligation on the TO, GO, or DP to follow RRO and RC approved criteria, this makes PRC-023-1 a "fill-in-the-blank" standard. Section 215 of the U.S. Federal Power Act does not allow enforcement of a reliability standard upon a bulk power system owner, operator or user, including the setting of financial penalties and sanctions, to the extent a portion of the requirements exists outside the standard. However, Section 215 of the U.S. Federal Power Act does allow for a Regional Entity to establish a regional reliability standard through a NERC approved procedure to make the requirements listed in R2 enforceable. Section 215 does not grant a similar right to the RC. Accordingly, the Regional Reliability Standards Working Group (RRSWG) recommends that references to the RC in R2 and M2 of this standard be removed.<br><br>The RRSWG suggests that if the intent of the drafting team is to have a regional reliability standard developed to support the NERC standard by stating approval criteria and requirements unique to the region developing the supporting standard, that the standard be revised to show in section A.4 that it is applicable to the Regional Entity (RE), not RRO, and to clearly identify the RE requirements and measurements. If, instead, the intent of the drafting team is not to have a regional reliability standard developed, the RRSWG suggests that R2 and M2 be deleted or refined to remove the "fill-in-the-blank" characteristics. To do so, the drafting team might consider the following refinement to R2 that would remove the "fill-in-the-blank" characteristics. The refinement would be to have the TO, GO, or DP develop documentation that demonstrates its application of R1.6, R1.7, R1.8, R1.9, R1.12, or R.13 complies with the criteria in the PRC-023 Reference Document. This refinement may require an additional requirement of the entity to simply provide its relay application documentation to the RRO and the RC for its information and |

| Question #4 – Any conflicts with regulatory functions, etc.? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | use. The applicable measurement would be for the RRO to verify compliance with the PRC-023 Reference Document criteria. This refinement would also require the PRC-023 Reference Document to be incorporated as an attachment to the standard or written into the NERC standard as additional requirements.<br><br>It is not the intent of the RRSWG to be overly prescriptive here. It is only our intent to provide options to the drafting team which it might not have already considered. The RRSWG assumes the drafting team will implement the appropriate revisions to the draft standard. |
| Response: R2 has been changed to obtaining the agreement of the Planning Authority, Transmission Operator, and Reliability Coordinator with the resulting facility ratings. This change results only in the necessary notifications to assure that consistent facility ratings are used. | | | |
| BPA Transmission (1)<br>Lorissa Jones | ☑ | | |
| MRO (2) et al<br>Joseph Knight<br>Manitoba Hydro (3, 5, 6)<br>Robert Coish | | ☑ | However, there could be regulatory issues regarding, for example, vertical clearance issues, for the proposed overloading of lines. |
| Response: Fault protective relays are not intended to prevent code violations. | | | |
| Montana-Dakota Utilities (1)<br>Don Raveling | | ☑ | |
| WECC Reliability Coordination Working Group<br>Nancy Bellows – WAPA (2) | | ☑ | |
| Ameren (1)<br>John Rauschenbach | | ☑ | |
| First*Energy* (1, 3, 5, 6)<br>David Folk | | ☑ | |
| Entergy Services, Inc. (1)<br>Ed Davis | | ☑ | |
| NPCC CP9 Reliability Standards Working Group | | ☑ | |

| Question #4 – Any conflicts with regulatory functions, etc.? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Guy Zito – NPCC (2) | | | |
| Hydro One Networks Inc. (1, 3) – David Kiguel | | ☑ | |
| IESO (2)<br>Ron Falsetti | | ☑ | |
| AEP ( 1, 5, 6)<br>James H. Sorrels, Jr. | | ☑ | |
| JDRJC Associates (1)<br>Jim Cyrulewski | | ☑ | |
| So. California Edison (1)<br>Neil Shockey | | ☑ | |
| Progress Energy–Carolinas (1, 3, 5) – D. Bryan Guy | | ☑ | |
| Consumers Energy (3, 4)<br>Richard G. Cottrell | | ☑ | |
| SCE&G ERO Working Group<br>Sally Wofford | | ☑ | |
| NERC System Protection and Control Task Force<br>Jon Sykes | | ☑ | |
| National Grid (1)<br>Herb Schrayshuen | | ☑ | |
| PJM Reliability Services Division – Al DiCaprio (2) | | ☑ | |
| ISO/RTO Council<br>Charles Yeung | | ☑ | |
| AESO (2)<br>Anita Lee | | ☑ | |
| FRCC (2)<br>Eric Senkowicz | | ☑ | |

| Question #4 – Any conflicts with regulatory functions, etc.? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| New York ISO (2)<br>Michael Calimano | | ☑ | |
| So. Company Services, Inc. (1) – Jim Busbin | | ☑ | |
| AECI (1)<br>John F. Bussman | | ☑ | |
| Pepco Holdings, Inc. Affil. (1)<br>Richard Kafka | | ☑ | |
| SCE (1)<br>Neil Shockey | | ☑ | |
| Hydro-Québec TransÉnergie (1) – Roger Champagne | | ☑ | |
| SERC PCS<br>Susan Morris | | ☑ | |

5. **Do you agree with the proposed effective dates? If no, please identify which effective date should be modified and identify why.**

**Summary Consideration:** Many of the stakeholders do not agree with the effective dates of the standard. The drafting team did change the effective dates to bring them into conformance with the format requested by the Compliance Program and to reflect that the effective dates are linked to the approvals from applicable regulatory authorities and to clarify that Temporary Exceptions that have already been approved by the Planning Committee will be respected with respect to delayed compliance.
Entities should already have taken steps to come into compliance with the relay loadability review and mitigation activities directed by the Planning Committee through the SPCTF (as reported via the Regions). Entities should be in compliance with this proposed standard upon completion of the timetable for those Planning Committee activities.
Note that for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, the revise effective dates give entities at least 39 months following applicable regulatory approvals to become compliant.

| Question #5 – Agree with proposed effective dates? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| WECC Reliability Coordination Working Group<br>Nancy Bellows – WAPA (2) | | ☑ | RCCWG feels that implementation should be delayed until # 7 comments are accommodated. |
| Response: The implementation plan was revised to include a statement indicating that Temporary Exceptions that have already been approved by the Planning Committee will be respected when the standard becomes effective. | | | |
| First*Energy* (1, 3, 5, 6)<br>David Folk | | ☑ | Both 5.1 and 5.2 should be on the same cycle. Recommend the effective date be 1/1/09 to allow time to address "lessons learned" after the 7/1/08 Beyond Zone 3 completion date. However, if staggered effective dates are used for these two requirements, they should be 6 months later than those stated to allow for incorporating "lessons learned". |
| Response: The industry has had since the end of 2004 to address lessons learned and no additional time is needed for that purpose.<br>Note that for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, entities have at least 39 months following applicable regulatory approvals to become compliant. | | | |
| Ameren (1)<br>Robert Rauschenbach | | ☑ | Utilities should be given at least two years to meet new requirements. One year to budget and plan, another for implementation. |
| Response: If the entity has conformed to the relay loadability review and mitigation activities directed by the Planning Committee through the SPCTF (as reported via the Regions), they should be in compliance with this proposed standard upon completion of the timetable for those activities. The SDT will include, in the implementation plan, that requests for Temporary Exceptions that have already been approved by the Planning Committee will be respected with respect to delayed compliance.<br>Note that for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, entities | | | |

| Question #5 – Agree with proposed effective dates? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| have at least 39 months following applicable regulatory approvals to become compliant. | | | |
| Entergy Services, Inc. (1)<br>Ed Davis | | ☑ | We believe that entities should be allowed a 2 year period after FERC approval of the standard to become compliant with these kinds of standards that may require significant capital investment. First, entities should not be considered non-compliant with any requirements of any standard that is not FERC approved. Second, once the standard is approved by FERC the entity should have one year to analyze his system for compliance and to budget funds to replace needed euqipment. The second year would be needed to install the equipment and ensure the proper operation of the equipment. |
| Response: If the entity has conformed to the relay loadability review and mitigation activities directed by the Planning Committee through the SPCTF (as reported via the Regions), they should be in compliance with this proposed standard upon completion of the timetable for those activities. The SDT will include, in the implementation plan, that approved requests for Temporary Exceptions that have already been approved by the Planning Committee will be respected with respect to delayed compliance.<br>Note that for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, entities have at least 39 months following applicable regulatory approvals to become compliant. | | | |
| Progress Energy–Carolinas (1, 3, 5) – D. Bryan Guy | | ☑ | PEC believes that the Implementation Plan for PRC-023 should be changed. Those needing to comply will need at least two years to meet new requirements once they are finalized. One year to budget and plan, another for implementation. Therefore effective date should be two (2) years from NERC BOT approval. |
| Response: If the entity has conformed to the relay loadability review and mitigation activities directed by the Planning Committee through the SPCTF (as reported via the Regions), they should be in compliance with this proposed standard upon completion of the timetable for those activities. The SDT will include, in the implementation plan, that approved requests for Temporary Exceptions that have already been approved by the Planning Committee will be respected with respect to delayed compliance.<br>Note that for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, entities have at least 39 months following applicable regulatory approvals to become compliant. | | | |
| SCE&G ERO Working Group<br>Sally Wofford | | ☑ | Utilities should be given more time, at least 2 years after BOT approval, to meet these requirements. One year to budget and plan and another year to implement. |
| Response: If the entity has conformed to the relay loadability review and mitigation activities directed by the Planning Committee through the SPCTF (as reported via the Regions), they should be in compliance with this proposed standard upon completion of the timetable for those activities. The SDT will include, in the implementation plan, that approved requests for Temporary Exceptions that have already been approved by the Planning Committee will be respected with respect to delayed compliance.<br>Note that for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, entities have at least 39 months following applicable regulatory approvals to become compliant. | | | |
| BPA Transmission (1)<br>Lorissa Jones | | ☑ | The proposed effective date of January 1, 2008 for transmission lines operated above 200 kV, etc. is appropriate, but the July 1, 2008 deadline for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100kV to 200 kV as designated by the regional reliability organization is not adequate because all of the regional reliability organizations have not yet designated which lines and transformers will fall under this requirement. The proposed effective date for these lines and transformers should be at least two years after the regional reliability organization has |

| Question #5 – Agree with proposed effective dates? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | designated the lines and transformers that are required to meet this reliability standard. |
| Response: The effective dates have been modified. Note that for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, entities have at least 39 months following applicable regulatory approvals to become compliant. | | | |
| SERC PCS<br>Susan Morris | | ☑ | Utilities should be given at least two years to meet new requirements. One year to budget and plan, another for implementation, i.e., 2 years from NERC BOT approval. |
| Response: If the entity has conformed to the relay loadability review and mitigation activities directed by the Planning Committee through the SPCTF (as reported via the Regions), they should be in compliance with this proposed standard upon completion of the timetable for those activities. The SDT will include, in the implementation plan, that approved requests for Temporary Exceptions that have already been approved by the Planning Committee will be respected with respect to delayed compliance.<br>Note that for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, entities have at least 39 months following applicable regulatory approvals to become compliant. | | | |
| AESO (2)<br>Anita Lee | | ☑ | The effective date for the circuits described in 4.1.2 and 4.1.4 (transmission lines and transformers with low votage terminal at 100 kV to 200 kV) should be a certain time period after the determination by the Regional Reliability Organization of such circuits, rather than the proposed fixed effective date of July 1, 2008. This will address the concern that some RROs may be late in making those determinations. It is also not clear as to where is the requirement for the RROs to make such determination and how often a review should be made. |
| Response: The effective dates have been modified in response to comments. | | | |
| AECI (1)<br>John F. Bussman | | ☑ | The Transmission owners need enough time to prepare the calculation, determine setting and plan setting changes within their region. One year after board approval should be enough time. |
| Response: If the entity has conformed to the relay loadability review and mitigation activities directed by the Planning Committee through the SPCTF (as reported via the Regions), they should be in compliance with this proposed standard upon completion of the timetable for those activities. The SDT will include, in the implementation plan, that approved requests for Temporary Exceptions that have already been approved by the Planning Committee will be respected with respect to delayed compliance.<br>Note that for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, entities have at least 39 months following applicable regulatory approvals to become compliant. | | | |
| Manitoba Hydro (3, 5, 6)<br>Robert Coish<br><br>MRO (2) et al<br>Joseph Knight | | ☑ | (1) 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 RRO's are required to make this designation should be recommended by the SDT and added to the implementation plan.<br><br>(2) Regarding implementation plan, one would have expected an implementation time frame of 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 |

| Question #5 – Agree with proposed effective dates? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | 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 are 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? |
| Response: (1) The effective dates have been modified in response to comments. (2) If the entity has conformed to the relay loadability review and mitigation activities directed by the Planning Committee through the SPCTF (as reported via the Regions), they should be in compliance with this proposed standard upon completion of the timetable for those activities. The SDT will include, in the implementation plan, that approved requests for Temporary Exceptions that have already been approved by the Planning Committee will be respected with respect to delayed compliance.<br>Note that for transmission lines operated at 100 kV to 200 kV and transformers with low voltage terminals connected at 100 kV to 200 kV, entities have at least 39 months following applicable regulatory approvals to become compliant. | | | |
| Consumers Energy (3, 4)<br>Richard G. Cottrell | | ☑ | The implementation plan should allow for previously-approved "Temporary Exceptions" to the criteria within the Standard, or delayed mitigation, to be accepted as a mitigation plan under Compliance Monitoring with no findings of non-compliance as long as the established and approved mitigation plan is followed. |
| Response: The SDT will include, in the implementation plan, that approved requests for Temporary Exceptions that have already been approved by the Planning Committee will be respected with respect to delayed compliance. | | | |
| Old Dominion Electric Coop. (4) – Mark Ringhausen | | ☑ | |
| AEP ( 1, 5, 6)<br>James H. Sorrels, Jr. | ☑ | | The implementation plan, however, should allow for previosly approved "Temporary Exceptions" to the criteria, within the Standard, as an approved mitigation plan with regard to Compliance Monitoring. The Compliance Monitoring should not result in a finding of non-compliance as long as the "Temporary Exception" mitigation plan is being followed. |
| Response: The SDT will include, in the implementation plan, that approved requests for Temporary Exceptions that have already been approved by the Planning Committee will be respected with respect to delayed compliance. | | | |
| NERC System Protection and Control Task Force<br>Jon Sykes | ☑ | | The implementation plan should allow for previously-approved "Temporary Exceptions" to the criteria within the Standard, or delayed mitigation, to be accepted as a mitigation plan under Compliance Monitoring with no findings of non-compliance as long as the mitigation plan is followed. These previously-approved "Temporary Exceptions" will have been approved within the "NERC 8a" and/or "Beyond Zone 3" review process by the NERC System Protection and Control Task Force with the concurrence of the NERC Planning Committee. |
| Response: The SDT will include, in the implementation plan, that approved requests for Temporary Exceptions that have already been approved by the Planning Committee will be respected with respect to delayed compliance. | | | |
| Montana-Dakota Utilities (1)<br>Don Raveling | ☑ | | |
| NPCC CP9 Reliability Standards | ☑ | | |

| Question #5 – Agree with proposed effective dates? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Working Group<br>Guy Zito – NPCC (2) | | | |
| Hydro One Networks Inc. (1, 3) – David Kiguel | ☑ | | |
| IESO (2)<br>Ron Falsetti | ☑ | | |
| JDRJC Associates (1)<br>Jim Cyrulewski | ☑ | | |
| So. California Edison (1)<br>Neil Shockey | ☑ | | |
| National Grid (1)<br>Herb Schrayshuen | ☑ | | |
| PJM Reliability Services Division – Al DiCaprio (2) | ☑ | | |
| ISO/RTO Council<br>Charles Yeung | ☑ | | |
| FRCC (2)<br>Eric Senkowicz | ☑ | | |
| New York ISO (2)<br>Michael Calimano | ☑ | | |
| So. Company Services, Inc. (1) – Jim Busbin | ☑ | | |
| Pepco Holdings, Inc. Affil. (1)<br>Richard Kafka | ☑ | | |
| SCE (1)<br>Neil Shockey | ☑ | | |
| Hydro-Québec TransÉnergie (1) – Roger Champagne | ☑ | | |

## 6. Do you agree with the proposed violation risk factors?

If no, please identify which requirement's risk factors you disagree with and identify what you think the risk factor should be and why.

**Summary Consideration:** Most stakeholders agreed that the ratings are correct. The rating for R2 was changed from lower to medium, to align with the changes made to the requirement based on stakeholder feedback in response to other questions.

| Question #6 – Agree with proposed violation risk factors? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Progress Energy–Carolinas (1, 3, 5) – D. Bryan Guy | | ☑ | The Risk Factor for R1 should be Low. The standard may be new but the engineering of zone relay settings is not. Also it is unlikely that missing a setting will result in cascading outages. |
| Response: The definition of high risk includes situations that, "could directly cause or contribute to" a cascading sequence of failure. Studies of the major North American blackouts have identified that protective relay operation on load currents was very much a direct contributor. It appears that the historical engineering of zone relay settings has not adequately considered their behavior during extremely stressed system conditions. | | | |
| Manitoba Hydro (3, 5, 6) Robert Coish | | ☑ | Manitoba Hydro feels that the more appropriate violation risk factor is medium because implementing this standard will not prevent the initiation of a blackout event. |
| Response: The definition of high risk includes situations that, "could directly cause or contribute to" a cascading sequence of failure. Studies of the major North American blackouts have identified that protective relay operation on load currents was very much a direct contributor. | | | |
| MRO (2) et al Joseph Knight | | ☑ | 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. |
| Response: The definition of high risk includes situations that, "could directly cause or contribute to" a cascading sequence of failure. Studies of the major North American blackouts have identified that protective relay operation on load currents was very much a direct contributor. | | | |
| PJM Reliability Services Division – Al DiCaprio (2) | | ☑ | A risk factor of High for a requirement that is related to a methodology seems excessive. Not using the suggested criteria will not de facto cause instability or cascading et al. |
| Response: The definition of high risk includes situations that, "could directly cause or contribute to" a cascading sequence of failure. Studies of the major North American blackouts have identified that protective relay operation on load currents was very much a direct contributor. It appears that the historical engineering of zone relay settings has not adequately considered their behavior during extremely stressed system conditions. | | | |
| FRCC (2) Eric Senkowicz | | ☑ | R1 should be a "medium" risk factor because of the inherent potential of mis-applied settings affecting BES system performance. However, an incorrect relay setting or a mis-applied relay settting, by itself, is unlikely to lead to the effects on the BES as described in the definition of a "high" risk factor. For the setting to affect the BES to the degree as described in the definition of "high" risk factor, multiple other core operational requirements would have had to have been violated. Therefore, for a mis-applied setting to affect the overall reliable response of a system to a particular disturbance, the effects on the system would be a result of multiple requirement |

| Question #6 – Agree with proposed violation risk factors? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| | | | violations, including the lack of appropriate monitoring and analysis along with inadequate operator intervention at posturing an affected system,. |
| Response: The definition of high risk includes situations that, "could directly cause or contribute to" a cascading sequence of failure. Studies of the major North American blackouts have identified that protective relay operation on load currents was very much a direct contributor. It appears that the historical engineering of zone relay settings has not adequately considered their behavior during extremely stressed system conditions. | | | |
| Entergy Services, Inc. (1)<br>Ed Davis | | ☑ | |
| Hydro One Networks Inc. (1, 3) – David Kiguel | | ☑ | |
| IESO (2)<br>Ron Falsetti | ☑ | ☑ | Agree with the violation risk factor for R.1 but not sure about the "Lower" ranking for R.2. The RRO or RC approval process only strengthens the standard apart from the fact that it provides a platform for communication between the RC and the transmission / generator owners who would primarily be responsible for the settings. Also, the RC or RRO would have a bigger picture of the various regions and it would be relatively easier for them to analyze the impacts of the various settings on a regional level as compared to a more localized level. |
| Response: In defining the VRFs the SDT felt that the APPROVAL of the RRO and RC (or lack thereof) was unlikely to directly impact a cascading event; thus the "lower" rating. | | | |
| Montana-Dakota Utilities (1)<br>Don Raveling | ☑ | | What are the violation risk factors to be used for? |
| Response: The violation risk factors are one element used to determine an appropriate sanction. The sanctions guideline are posted on the NERC web site as Appendix 4 in NERC's ERO Application: http://www.nerc.com/~filez/ero/ero_applications.html | | | |
| WECC Reliability Coordination Working Group<br>Nancy Bellows – WAPA (2) | ☑ | | |
| AEP ( 1, 5, 6)<br>James H. Sorrels, Jr. | ☑ | | Please note that only a VRF should be assigned to R1 since each of the sub clauses of R1 is a method for accomplishing the R1 requirement. |
| Response: Acknowledged. | | | |
| NERC System Protection and Control Task Force<br>Jon Sykes | ☑ | | As reflected in the draft Standard, the VRF for R1 must apply to only R1 in its entirety, and not to each individual sub-clause of R1, in order to accurately reflect the phrase within R1, "any one of the following criteria..." |
| Response: Acknowledged. | | | |

| Question #6 – Agree with proposed violation risk factors? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| BPA Transmission (1)<br>Lorissa Jones | | | I think that the risk factor should be high. |
| Response: R1 is high. | | | |
| Ameren (1)<br>John Rauschenbach | ☑ | | |
| First*Energy* (1, 3, 5, 6)<br>David Folk | ☑ | | |
| NPCC CP9 Reliability Standards Working Group<br>Guy Zito – NPCC (2) | ☑ | | |
| JDRJC Associates (1)<br>Jim Cyrulewski | ☑ | | |
| Old Dominion Electric Coop. (4) – Mark Ringhausen | ☑ | | |
| So. California Edison (1)<br>Neil Shockey | ☑ | | |
| Consumers Energy (3, 4)<br>Richard G. Cottrell | ☑ | | |
| SCE&G ERO Working Group<br>Sally Wofford | ☑ | | |
| National Grid (1)<br>Herb Schrayshuen | ☑ | | |
| New York ISO (2)<br>Michael Calimano | ☑ | | |
| So. Company Services, Inc. (1) – Jim Busbin | ☑ | | |
| AECI (1)<br>John F. Bussman | ☑ | | |
| Pepco Holdings, Inc. Affil. (1)<br>Richard Kafka | ☑ | | |

| Question #6 – Agree with proposed violation risk factors? | | | |
|---|---|---|---|
| **Commenter** | **Yes** | **No** | **Comment** |
| Hydro-Québec TransÉnergie (1) – Roger Champagne | ☑ | | |

**7. If you have other comments or specific suggestions for improvements to this standard that you have not already made, please provide them here:**

| Question #7 – Other comments on the standard? | |
|---|---|
| **Commenter** | **Comment** |
| Montana-Dakota Utilities (1)<br>Don Raveling | Are there any recommendations for line thermal relays? Or, are they considered to be SPSs? |
| Response: No recommendations are being made relative to line thermal relays; Attachment A has been modified to specifically exclude protective elements that respond more slowly than 15 minutes. The unstated expectation is that line thermal relays will support the assigned Facility Rating. | |
| NPCC CP9 Reliability Standards Working Group<br>Guy Zito – NPCC (2) | Guidance on applying the standard to "switch on to fault" SOTF should be provided in the reference document. |
| Response: Appendix D has been added to the reference document to address SOTF. | |
| So. California Edison (1)<br>Neil Shockey | Reference R1.10 and R1.11 Is should be clear that where the relay protection referred to does not exist, that R1.10 and R1.11 are not requiring their installation, only describing their performance should they exist. |
| Response: The standard does not require that specific relays be present on the system. | |
| WECC Reliability Coordination Working Group<br>Nancy Bellows – WAPA (2) | R2, 2.1, 2.2, 2.3, and M2 all require the Regional Reliability Organization (RRO), as well as the Reliability Coordinator, approve protective relay settings. This determination should be made at the Regional Reliability Organization. |
| Response: Changes have been made to the standard and the standard now requires that the responsible entities obtain 'agreement' from the RC, TOP and PA' – the standard does not include the word, 'approve'. The RRO was removed as a responsible entity. If the RRO registers to be a PA (or PC) then the RRO will be performing this duty as the PA, not as the RRO. Moving forward, standards will not be written with requirements assigned to the RRO. | |
| Ameren (1)<br>Robert Rauschenbach | Introduction section:<br><br>4.1.2 Critical facilities between 100 kV and 200 kV need further definition. Each of the regions will interpret this differently. Perhaps facilities between 100 kV and 200 kV should not be included as critical until a clear definition is provided.<br><br>Requirements section: |

| Question #7 – Other comments on the standard? | |
|---|---|
| **Commenter** | **Comment** |
| | R1.3.1 and R1.3.2 The use of 0.85 per unit voltage for relay load limit is redundant. The maximum power transfer is calculated at 1.0 per unit. The 115% factor in R1.3 already provides margin.<br><br>R1.5 This doesn't make sense. How can the line carry a maximum load of 1.7 multiplied by the end of line 3-phase fault? This requirement should be removed.<br><br>R1.6 It is not clear how the 230% factor is derived. Is this 2.0 times the generation rating time a 1.15 multiplier? For parallel lines, how many contingencies should be considered? With 4 lines in parallel, would 3 lines be assumed out-of-service? This does not appear realistic. Further definition is needed. Justification for requirements beyond those shown in NERC's Table-1 should be provided.<br><br>R1.8 The term 'any system configuration' is ambiguous and confusing. It is not clear how many contingencies should be considered. As is R1.6, further definition is needed, and justification for requirements beyond those shown in NERC's Table-1 should be provided.<br><br>R1.9 It seems R1.7 is covered under R1.9.<br><br>R1.12 The necessity to cover remote lines under breaker failure conditions is not addressed. Remote breaker failure coverage is required on breaker-and-a-half, ring-bus, and in-line breaker applications. The 1.25 coverage of these breaker failure conditions should be included as an exception.<br><br>R1.12.3 There is already margin in the relay load limit calculation. There is no need for an additional restriction on the facility rating. This is operationally burdensome and confusing to carry two load limit numbers.<br><br>R2 R2.1, R2.2, and R2.3 appear redundant. R2 already states approval is required from Regional Reliability Organization and Reliability Coordinator. The relay load limits should be included in all facility ratings. |
| Response:<br>Introduction Section<br>4.1.2 – Only the Reliability Coordinator can determine which facilities are critical to reliability within the region. In some areas of North America, 138 kV, 161 kV, 230 kV, or other similar voltage class lines are very critical to the reliability of the BES, and need be considered. In other areas, with extensive higher-voltage transmission systems, these systems have the characteristic of high-voltage distribution lines.<br><br>Requirements Section | |

| Question #7 – Other comments on the standard? | |
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| **Commenter** | **Comment** |
| R1.3 – The 1.0 per unit voltage is based on converting the maximum power transfer to amps. The 0.85 per unit voltage is based on measured voltage during extreme operating conditions. A 15% margin is needed beyond these two expected values.<br><br>R1.5- This is supplied to reflect the maximum power that can flow from a weak source terminal, based on the fault current source at that terminal. Detailed information is supplied in the reference document.<br><br>R1.6 – Yes – the 230% is 115% above 200%. As for the number of contingencies, it's as many as it takes to get to one line left, unless SPS's prevent operation of the generator for such conditions.<br><br>R1.8 – It is as many contingencies as it takes to get to one line left. Detailed information is supplied in the reference document.<br><br>R1.9 – While the requirements may seem similar, the requirements address different topology.<br><br>R1.12 – Requirement R1.12 is designed to provide a reduced facility rating based on minimum line protection. There are many ways to accomplish breaker-failure-protection beyond simple use of mho characteristic step distance relays. Such methods include use of direct-transfer-trip communications and use of relay characteristics (lens, load encroachment, etc) that permit enhanced relay loadability while still providing necessary protection.<br><br>R1.12.3 – R1.12.2 calculates the relay loadability based on the extreme conditions observed in past blackouts. R1.12.3 establishes the facility ratings by applying a 15% margin to account for relay and instrument transformer error consistent with the other criteria under R1.<br><br>R2 – These have a subtle difference, in that one asks for regional concurrence on the rating used, and the other establishes a new rating. These requirements have been modified in the new draft of the standard. | |
| First*Energy* (1, 3, 5, 6)<br>David Folk | R1 Include the words "load carrying" in front of capability.<br>R1.1 Please confirm that the 150% margin that is added on top of the 0.85 p.u. voltage and 30 degree power factor angle is not too large. Would a margin of 125-130% be sufficient? This would have a tendency to provide an increased level of protection for the transmission system.<br>The voltage used to evaluate loadability at generating switchyard buses should not be lower than the value at which the plant auxiliary systems can be operated.<br>R1.11 This requirement is not clearly stated. Why is it referring to R1.10? R1.10 is for fault protection relays and R1.11 is for overload relays and they say virtually the same thing. The wording in R1.11 does not reflect the intent of the reference document. The reference document section similar to R1.11 allows for lower settings with supporting documentation. Therefore reference to R1.11 should be included in M2.<br>R1.12 Include the words "load carrying" in front of capability.<br>M2 What is meant by the terms circuit rating and facility rating? Do they need special definitions.<br>General : |

| Question #7 – Other comments on the standard? | |
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| **Commenter** | **Comment** |
| | Should this standard include definitions for several special terms used in this standard?<br>Consider a bi-annual review and self-certification or data submittal rather than an annual review. |
| Response: R1 and R1.12 - Adding the words “load carrying” would be redundant with what is already stated.<br>R1.1 – The 150% is necessary to provide the system operator with adequate response time for extreme system conditions and also account for errors in the relaying system.<br>The generation aux power voltage may differ greatly from the transmission system voltage; the voltage referenced is difficult to quantify in a standard. If this is an issue in a specific example, R1.13 can be used.<br>R1.11 – R1.11 refers specifically to relays used for transformer overload protection and provides some additional flexibility to reflect the actual parameters affected by overloads.<br>M2 – Changes have been made to the Standard to clarify that the responsible entity’s facility rating was agreed to by its associated Planning Authority, Transmission Operator, and Reliability Coordinator.<br>The SDT is not aware of any special terms that need to be defined.<br>Most stakeholders who responded seem to indicate support for an annual review. | |
| Hydro One Networks Inc. (1, 3) – David Kiguel | Requirement R1: The phrase "The relay performance should be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees" should clearly state that the requirement applies only to RELAYS that are sensitive to voltage and/or power factor angle.<br>Requirement R1.1 remove the word "seasonal" that precedes "Facility Rating of a circuit."<br>Requirement R2 and Measure M2 make reference to requirement R.13 It should read R1.3 instead.<br>References to requirements in the documents use the full word (e.g. Requirement 1.12 in R2.20 or the abbreviation Rx.y (e.g. R1.6 in R2). We recommend consistency in the use of these references. |
| Response: R1 – The drafting team feels that this clarification is unnecessary. If a relay is not sensitive to these quantities, it should be clear that they need not be considered.<br>R1.1 – Facility Ratings may be specified on a seasonal basis. Therefore, the drafting team feels that it is important to emphasize that the highest of various seasonal Facility Ratings be used.<br>R2/M2 – Acknowledged. | |
| IESO (2)<br>Ron Falsetti | Level 3 incorporates the clause: "… and the relay settings were causal to a Reportable Disturbance". We feel that improper or incorrect device settings or maintenance could lead eventually to that particular device being the cause of a disturbance or a reportable event. However, this should not be the basis for the violation. Linking a compliance level to a causal effect should not be part of a standard as this would render this particular standard inconsistent with the other standards.<br>We believe that the level orders are reversed for Level 3 and Level 4. Level 3 actually refers to "non-compliance" through the statement: "Relay settings do not comply…" whereas Level 4 is referring to "supporting evidence or documentation" through the statement: "Evidence does not exist…". From the language, it clearly seems to indicate that Level 3 is more stringent than Level 4. |

| Question #7 – Other comments on the standard? | |
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| **Commenter** | **Comment** |
| | We feel that L 2.2.1 is incorrectly stated. In its present form, it states that "Evidence that relay settings comply with one of the criteria in R.1.1 through R1.13 exists but is incomplete or incorrect". This statement should be revised as "Evidence that relay settings comply with the criteria in R1.1 through R1.13 exists but is incomplete or incorrect for one or more of the requirements". |
| Response:<br>The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability. | |
| Entergy Services, Inc. (1)<br>Ed Davis | Level 3 and level 4 non-compliance criteria should be swapped since level 3 is a more severe "violation" than level 4. |
| Response: The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability. | |
| AEP ( 1, 5, 6)<br>James H. Sorrels, Jr. | Level three and four seem to be reversed. Level three is dealing with a relay that actually caused an event due to not meeting the Loadability Standard requirements, while level four deals with the documentation of a relay's compliance with the Loadability Standard. Also, if the two levels are reversed, should it matter how a relay is discovered to be in non-complance with the Loadability Standard? The new level four should read: Relay settings that do not comply with the loadability criteria in R1.<br>The last sentence of R1 is stated for distance relay evaluation. A method to evaluate other relays should be worked into this sentence. |
| Response: The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability.<br>R1 – The drafting team feels that this evaluation is appropriate for all load-responsive relays. If voltage and/or power factor do not impact the performance of a specific relay technology, it should not be necessary to state that they do not need to be considered. | |
| Consumers Energy (3, 4)<br>Richard G. Cottrell | It seems that the Level 3 and Level 4 non-compliance are reversed in their severity and priority. Also, there are errors in R2 and M2; "Requirement 13" should be "R1.13", and please use a consistent approach to referencing other requirements - "Requirement" or "R". |
| Response: The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability.<br>Typos acknowledged. | |
| SCE&G ERO Working Group<br>Sally Wofford | Requirements Section:<br>R1 Opening paragraph: "The relay performance shall be evaluated at 0.85 per unit voltage and a power factor |

| Question #7 – Other comments on the standard? | |
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| **Commenter** | **Comment** |
| | angle of 30 degrees. Suggest that this sentence be clarified to state that it applies only to relays sensitive to voltage and/or power factor angle.<br>R1.2.1 and R1.3.2 Reference Document - The calculation of maximum power transfer at 1.0 per unit seems to be inconsistent with the use of 0.85 pu voltage for the relay load limit.<br>R1.5 Reference Document - More explanation is needed to avoid confusion.<br>R2 In the text of R2, R.13 should be R1.13. R2.1 and R2.2 appear to be easily combined.<br>Non-Compliance Levels<br>Suggest that non-compliance levels 3 & 4 be exchanged. It seems that non-compliance resulting in a reportable disturbance is more serious than ….evidence does not support…. |
| Response:<br>R1 – The drafting team feels that this clarification is unnecessary. If a relay is not sensitive to these quantities, it should be clear that they need not be considered.<br>R1.2.1 and R1.3.2 – The 1.0 per unit voltage is based on converting the maximum power transfer to amps. The 0.85 per unit voltage is based on measured voltage during extreme operating conditions.<br>R1.5 – More explanation of your confusion is needed by the SDT to address your comment.<br>R2 - The text of R2 should have been R1.13 as indicated. This has been corrected.<br>R2.1 and R2.2 were modified and combined in support of your suggestion and other suggestions made by other stakeholders.<br>The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability. | |
| Manitoba Hydro (3, 5, 6)<br>Robert Coish<br><br>MRO (2) et al<br>Joseph Knight | (1) Manitoba Hydro (MRO) has a concern with the 15% additional margin applied to the facility rating. This can be considered a negative margin worth 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.<br><br>(2) Does this standard expose the TO etc. to legal risk if there is damage to the public (violating vertical clearances for example)<br><br>(3) 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. |

| **Question #7 – Other comments on the standard?** | |
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| **Commenter** | **Comment** |
| | (4) 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 pu voltage, and power factor angle of 30 degrees. criteria may not be appropriate for all cases.<br><br>(5) If you have too prescriptive a standard you may discourage people coming up with adaptive solutions.<br><br>(6) This standard removes the option of using zone three relays to provide more reliable system operation<br>(a) For internal lines – it may not be possible to set an out of step relay to block tripping on a true out of step condition. (Moving blinders in may make it impossible to detect fast moving swings)<br><br>(b)On interties: It may not be possible to set relays to detect fastest swing to be able to trip the tie – as a consequence, undesired tripping of other lines may occur.<br><br>(7) This standard seems to be precluding the concept of TO's 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.<br><br>(8) R2.1 and R2.2 could be combined by adding 1.12 to the list in R2.1 and removing R2.2<br><br>(9) In M1 and M2 it should be further clarified what is meant by "evidence".<br><br>(10) In R2, why would it be necessary to get approval of the RRO and RC? If each criteria choice is valid, why is this necessary? This is unnecessary bureaucracy.<br><br>(11) Is the interpretation of R1 that the TO etc. could more that one criteria within their system?<br><br>(12) In Appendix A what is meant by: 1.2.3 Protection systems intended for protection during stable power swings?<br><br>(13) On page 6, R1.1.2, I in the formula for Zrelay30, should 1.5 be 1.1? |
| Response: (1) System protection systems are designed to remove faults. Typically, system protection criteria do not include preventing equipment damage from over load conditions. Operator action is required to protect facilities from overload conditions per NERC Standard TOP- | |

| Question #7 – Other comments on the standard? | |
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| **Commenter** | **Comment** |
| 008-0, R3. If facility overload protection is desired, it should be provided by protective elements designed and applied expressly for overload protection incorporating appropriate time delays which permit the operator time to respond.<br>(2) Fault protective relays are not intended to prevent code violations.<br>(3) Fault protective relays are not intended to prevent thermal overloads.<br>(4) R1.13 permits such studies.<br>(5) There is ample opportunity for entities to develop adaptive solutions and still maintain loadability.<br>(6) The conditions you present may need protection expressly designed for those systems.<br>(7) R1.13 addresses the situation you present.<br>(8) R2.1 and R2.2 were modified and combined in support of your suggestion and other suggestions made by other stakeholders.<br>(9) The Standard can not be overly prescriptive in this area and can not impose additional requirements within the measures.<br>(10) Changes have been made to the standard.<br>(11) Yes. A Transmission Owner may use any criteria that is appropriate for each terminal.<br>(12) In some parts of North America (for example, in Florida), there are relay systems installed specifically to separate portions of the system that are experiencing stable power swings relative to each other to maintain desirable performance relative to voltage, frequency, and power oscillations.<br>(13) The SDT is not certain to which formula you refer. We have reviewed formulas in Reference Document clauses R1.1 and R1.2 and all are correct. | |
| Old Dominion Electric Coop. (4) – Mark Ringhausen<br><br>Progress Energy–Carolinas (1, 3, 5) – D. Bryan Guy | Regarding Levels of Non-Compliance, we would suggest that the criteria for Level 3 and the criteria for Level 4 should be exchanged. A violation resulting in a Reportable Disturbance seems to be more serious than "no evidence exists to support that relays comply with one of the criteria …". The existing Level 3 should also be "causal or contributory" instead of just "causal". It would also seem that a non-compliance with the relay loadability criteria (either evidentiary or on the physical relay) , whether causal to a Reportable Disturbance or not, should be identified within the Levels of Non-Compliance. Perhaps, this should be reflected by "Evidence indicates that relay settings do not comply with R1.1 through R1.13." as a Level 4 non-compliance.<br><br>Requirements section:<br>Reference the last sentence of R1. "The relay performance shall be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees." We suggest that this sentence should more clearly state that it applies only to relays that are sensitive to voltage or power factor angle.<br>R1.3.1 and R1.3.2 The calculation of maximum power transfer at 1.0 per unit is inconsistent with the use of 0.85 per unit voltage for relay load limit.<br>R1.5 More explanation should be included in this requirement. The present wording is somewhat ambiguous as to the intent, and more detail should be included to avoid confusion.<br>R1.6 The standard and the reference document need to limit the application of this criteria on multiple lines out of a generation center to a 3 line situation. While it is agreed that the 3 line situation where 2 lines become |

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<tr><td></td><td>outaged is forseable (i.e. one line is out for maintenance and a fault occurs on the second line), applying this scenario to more multiples becomes more and more unlikely.<br>R1.9 It seems R1.7 is covered under R1.9. Please explain why both are needed.<br>R2 R2.1 and R2.2 appear redundant. R2 already states approval is required from Regional Reliability Organization and Reliability Coordinator. The relay load limits should be included in all facility ratings.</td></tr>
<tr><td colspan="2">Response: The ‘levels of non-compliance’ were all replaced with ‘violation severity levels’ to conform to the ERO Rules of Compliance. While ‘levels of non-compliance’ were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability.<br>Requirements Section<br>R1 – The drafting team feels that this clarification is unnecessary. If a relay is not sensitive to these quantities, it should be clear that they need not be considered.<br>R1.31 and R1.3.2 - The 1.0 per unit voltage is based on converting the maximum power transfer to amps. The 0.85 per unit voltage is based on measured voltage during extreme operating conditions.<br>R1.5 – The standard provides a concise statement of the requirement. For the basis of the requirement and supporting material, please see the reference document.<br>R1.6 – The conservative nature of this requirement is intentional. The probability is low but the impact is high.<br>R1.9 and R1.7 - While the requirements may seem similar, the requirements address different topology.<br>R2 - R2.1 and R2.2 were asking for slightly different things – they have modified and combined in support of suggestions made by other stakeholders.</td></tr>
<tr><td>NERC System Protection and Control Task Force<br>Jon Sykes</td><td>Regarding Levels of Non-Compliance, we would suggest that the criteria for Level 3 and the criteria for Level 4 should be exchanged. A violation resulting in a Reportable Disturbance seems to be more serious than "no evidence exists to support that relays comply with one of the criteria …". The existing Level 3 should also be "causal or contributory" instead of just "causal". It would also seem that a non-compliance with the relay loadability criteria (either evidentiary or on the physical relay) , whether causal to a Reportable Disturbance or not, should be identified within the Levels of Non-Compliance. Perhaps, this should be reflected by "Evidence indicates that relay settings do not comply with R1.1 through R1.13." as a Level 4 non-compliance.<br>Regarding R1 - The phrase "The relay performance shall be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees" should more clearly state that it applies only to RELAYS sensitive to voltage and/or power factor angle. For example, we suggest "Relay load-carrying capacity (in amperes) shall be evaluated at 0.85 per unit voltage and at a power factor angle of 30<br>degrees for relays sensitive to voltage and/or power factor angle, and shall be evaluated directly for overcurrent relays."<br><br>Regarding R1.10 - "Transformer protection relays and relays on transformer terminated lines shall be set so that they do not operate at or below the greater of:"</td></tr>
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| Question #7 – Other comments on the standard? | |
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| **Commenter** | **Comment** |
| | Editorial Comments - In R2 and M2, "Requirement 13" should be "R1.13". Also, in R2.2, R2.3, and M2, please use a consistent reference to various requirements; either "Requirement …" or R…"<br><br>Although we understand the reasoning behind tying Level 4 non-compliance to a reportable disturbance, it seems to be inappropriate to do so in this Standard. No requirement is established within the Standard that specifies that a non-compliance shall not contribute to a reportable disturbance. Standards set forth Requirements and Measures by which compliance with the requirements will be assessed. The Levels of Non-Compliance must be tied back to the Measures; they should not introduce additional de facto requirements beyond those already set forth in the Requirements section, e.g. not causing a reportable disturbance. While I agree that causing a reportable disturbance is a significant concern, I feel it is inappropriate to incorporate penalties for doing so in every (or even one) Standard for which non-compliance may lead to a reportable disturbance. Failure to comply with the Standard should have one penalty associated with it based on the Level of Non-Compliance defined in the Standard. If penalties are to be assessed for causing a reportable disturbance, this should be done outside of the Compliance section of each and every Standard for which non-compliance could lead to a reportable disturbance. Establishing such penalties outside the Standards would ensure uniform treatment for all such events. |
| Response:<br>The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability.<br>Standards Section<br>R1 – The drafting team feels that this clarification is unnecessary. If a relay is not sensitive to these quantities, it should be clear that they need not be considered.<br>R1.10 - The standard was changed in support of your suggestion.<br>R2 and M2 - These clauses were changed extensively in the standard. In making these changes, the drafting team addressed the editorial comments that you noted. | |
| So. Company Services, Inc. (1) – Jim Busbin | Southern Company Transmission supports the following portion of the comments made by the NERC System Protection and Control Task Force:<br>"Regarding Levels of Non-Compliance, we would suggest that the criteria for Level 3 and the criteria for Level 4 should be exchanged. A violation resulting in a Reportable Disturbance seems to be more serious than 'no evidence exists to support that relays comply with one of the criteria . . . .' The existing Level 3 should also be 'causal or contributory' instead of just 'causal'. It would also seem that a non-compliance with the relay loadability criteria (either evidentiary or on the physical relay), whether causal to a Reportable Disturbance or not, should be identified within the Levels of Non-Compliance. Perhaps, this should be reflected by 'Evidence indicates that relay settings do not comply with R1.1 through R1.13' as a Level 4 non-compliance. |

| Question #7 – Other comments on the standard? | |
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| **Commenter** | **Comment** |
| | Regarding R1 - The phrase 'The relay performance shall be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees' should more clearly state that it applies only to RELAYS sensitive to voltage and/or power factor angle.<br>Editorial Comments - In R2 and M2, 'Requirement 13' should be 'R1.13'.  Also, in R2.2, R2.3, and M2, please use a consistent reference to various requirements; either 'Requirement . . . ' or 'R . . . .'" |
| Response: The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability.<br>R1 - The drafting team feels that this clarification is unnecessary. If a relay is not sensitive to these quantities, it should be clear that they need not be considered.<br>R2 and M2 - These clauses were changed extensively in the standard.  In making these changes, the drafting team addressed the editorial comments that you noted. | |
| National Grid (1)<br>Herb Schrayshuen | Section B -- Requirements<br>R1: The Standard should clarify that the protection system owner is free to select any of the criteria in R1.1 through R1.13 and need not apply the same one on all protection systems.<br>R11: The Standard should allow for overcurrent settings set below 150% of the maximum transformer nameplate rating or 115% of the highest operator established emergency transformer rating if the relays are supervised by a distance element that meets the relay loadability requirements.<br>R2: The reference to "R.13" should be "R1.13".  The same error is repeated under Section C - Measures at M2 and under Section D - Compliance at 2.1.1.<br>R2.1 and R2.2: Given the identical wording in these two requirements it is not clear to the reader why these two requirements could not be combined.  Additional text should be added to clarify that R2.1 pertains to criteria used to verify that the loading cannot be reasonably expected to exceed relay loadability, whereas R2.2 pertains to a criterion that establishes an equipment rating less than its actual capability based on the relay setting.<br>Section D -- Compliance<br>We do not agree with assigning different Levels of Non-Compliance depending on the method by which the non-compliance is identified.  The draft Standard sets forth the Requirements and the Measures by which compliance with the requirements will be assessed.  The Levels of Non-Compliance must be tied back to the Measures; they should not introduce additional de facto requirements beyond those already set forth in the Requirements section, e.g. not causing a reportable disturbance.  While we agree that causing a reportable disturbance is a significant concern, we feel it is inappropriate to incorporate penalties for doing so in every (or even one) Standard for which non-compliance may lead to a reportable disturbance.  Failure to comply with a Requirement in the Standard should have one penalty associated with it based on the Level of Non-Compliance defined in the Standard.  If penalties are to be assessed for causing a reportable disturbance, this should be done outside of the Standards.  Establishing such penalties outside the Standards would ensure |

| Question #7 – Other comments on the standard? | |
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| **Commenter** | **Comment** |
| | uniform treatment for all such events. |
| Response: R1 – The phrase, "for any specific circuit terminal" was inserted to address your comment.<br>R1.11 – R1.11 Supervising (or better yet, torque controlling) an overcurrent relay with a distance relay that meets the requirements clearly results in a protective application that "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". This does not represent a requirement, but instead a method of meeting the requirement. The drafting team does not feel that this needs to be added to the standard.<br>R2 – Typos have been addressed.<br>R2.1 and R2.2 - These clauses were combined, as suggested.<br>Section D – We agree that no part of the standard specifies that an incorrect relay should not contribute to a reportable disturbance. The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability. | |
| California ISO (2)<br>Brent Kingsford | R2, R2.1, R2.2, R2.3, and M2 list the Reliability Coordinators as an entity that is required to approve transmission relays set according to the criteria in R1.6, R1.7, R1.8, R1.9, R1.12, or R.13. We disagree with the standard listing Reliability Coordinators as an entity that will approve relay settings when set according to the criteria above. We are concerned that Reliability Coordinators may not be staffed with relay engineers and obtaining approval from the Reliability Coordinators would be perceived as validation of a setting when that approval would really only be an acknowledgement of the setting criteria.<br>Reliability Coordinator should be deleted from the requirements and measures listed above. |
| Response: R2 – "Approval" has been replaced with "Agreement", to reflect that the RC will adopt these loadability restrictions as the Facility Rating. | |
| PJM Reliability Services Division – Al DiCaprio (2) | Level 2 needs to be reworded. Level 2 implies "that evidence of COMPLIANCE exists" then states that the evidence is incomplete. Either it is compliant or it is incomplete.<br>The Level 3 and Level 4 non compliance seems to be reversed. Level 3 seems to be related to a more adverse result than does Level 4.<br>Reliability Coordinators are responsible for relay setting approvals (per R2, R2.1, R2.2, R2.3, and M2). The verification of relay settings is more appropriate at the Transmission Operator level. |
| Response:<br>The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability.<br>Paragraph 3 – "Approval" has been replaced with "Agreement", to reflect that the RC will adopt these loadability restrictions as the Facility Rating. A higher-level review of the relay settings themselves is not required by the standard. | |
| ISO/RTO Council | The IRC (AESO) favors standards that define performance requirements and measure compliance based on |

| Question #7 – Other comments on the standard? | |
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| Charles Yeung<br><br>AESO (2)<br>Anita Lee | that performance. The IRC (AESO) questions the incorporation of difference Levels of Compliance based on the cause of the given performance.<br>NERC already has a process that includes Violation Risk Factors and Violation Severity Levels to 'adjust' non-compliance penalties. To include another subjective adjustment factor would seem to be inappropriate.<br>The IRC (AESO) suggests that the SDT consider reversing the level orders for Level 3 and Level 4. From the language in the standard, the current Level 3 is more stringent than Level 4.<br>The IRC (AESO) does not agree that the Reliability Coordinators should be included as a responsible entity for relay setting approvals (per R2, R2.1, R2.2, R2.3, and M2). The IRC notes that not all RCs have appropriate expertise in making such determinations and therefore suggests that the verification of relay settings is more appropriate at the Transmission Operator level. Further the Functional Model White Paper does not include any relay setting or authorization responsibilities for the RC. |
| Response:<br>We agree that no part of the standard specifies that an incorrect relay should not contribute to a reportable disturbance.<br>The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability.<br>Paragraph 4 – "Approval" has been replaced with "Agreement", to reflect that the RC will adopt these loadability restrictions as the Facility Rating. A higher-level review of the relay settings themselves is not required by the standard. | |
| New York ISO (2)<br>Michael Calimano | The NYISO also supports the IRC comment that the Reliability Coordinators should not be included as a responsible entity for relay setting approvals (per R2, R2.1, R2.2, R2.3, and M2).<br>Also, guidance on applying the standard to "switch on to fault" SOTF should be provided in the reference document. |
| Response: "Approval" has been replaced with "Agreement", to reflect that the RC will adopt these loadability restrictions as the Facility Rating. A higher-level review of the relay settings themselves is not required by the standard. Appendix D was added to the Reference Document to address SOTF. | |
| FRCC (2)<br>Eric Senkowicz | Section 2.3 and 2.4 should be swapped with regards to Levels of Non-Compliance. A mis-applied setting that was causal to a Reportable Disturbance appears to be the worst-case infraction and therefore should be the "Level 4" Non-compliance.<br>Has the drafting team considered the concept of "temporary exceptions" to the setting criteria? One of the concerns expressed in our Region is that during certain system modifications, (i.e. new lines, configuration changes, ampacity upgrades, etc) it may be necessary to deviate from the prescribed criteria on a temporary basis, so that the necessary relaying modifications may be made to accommodate the system changes? This type of "temporary exception" would allow construction implementation without racking up a violation, and still maintaining adequate equipment protection.<br>Lastly, has the drafting team considered adding a "grace" period for resolving self-identified non-compliances |

| Question #7 – Other comments on the standard? | |
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| | to the setting requirements of this standard? As an example a "non-compliant" setting that is self-identified would be reportable but would not result in a non-compliance violation if the settings were corrected within a certain time period.<br>We appreciate the team's rigorous efforts at creating this complex standard and also appreciate the opportunity to provide the above comments. |
| Response:<br>The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability.<br>As for the question about "temporary exceptions" for in-progress system modifications - the standards to not provide a mechanism for non-compliance without resulting in a violation. The drafting team recommends that one of the other requirements be used to establish reduced facility ratings during such a period. For example, R1.13 establishes that the equipment owner may develop study based ratings for relay loadability applications and that those ratings become reflected in the facility ratings. Another approach to this issue would be to apply R1.12, again with full acceptance of the resulting reduced ratings.<br>Paragraph 3 – While there is no specified grace period, the penalties and sanctions calculator already incorporates reductions in fines and penalties if an entity self reports promptly and takes immediate corrective action. We believe this addresses your concern. | |
| AECI (1)<br>John F. Bussman | See SERC comments for the Level of non compliance section comments.<br>In R1. We are not sure of the basis for the .85pu voltage and 30 degrees phase angle.<br>R1.3.1 Agree with the SERC comment of the inconsistency of .85 vs 1.0 pu.<br>Agree with SERC comments regarding R1.6 R1.9 and R2<br>R1.5 We are concerned on how the transmission line being fed from a "weak source" can be protected if the line relays are set to not operate at or below 170% of the maximum end-of-line three-phase fault magnitude. It would seem that if a fault condition did exist at the end of the line, the relay would not clear this fault and would just serve it as load. More clarification is required regarding this setting<br>How does this standard apply to tapped lines that are greater than 200KV when the relays are set to trip the tapped line however not the main feeder line. |
| Response: See Response to SERC comments.<br>R1 - The industry actions relate relay loadability to system collapse. Therefore the use of 0.85 pu voltage and a 30 degree phase angle for relay performance calculations is appropriate. Studies into the various WECC collapses, into the 1967 blackout, and into August 2003 show that the system voltage becomes depressed and a 30 degree power factor angle is very common during the pre-collapse time periods, and it is these time periods during which the evaluation of the relay performance is most critical. These conditions were found to be typical under these conditions and by no means reflect worst case conditions.<br>R1.3.1 & R1.6 & R1.9 & R2 – See response to SERC comment.<br>R1.5 – A distance relay will operate for these conditions. Refer to the reference document for additional details.<br>Last comment – The standard applies to all terminals whether tapped or not. Different optional criteria from among the requirements may be | |

| Question #7 – Other comments on the standard? | |
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| useful for tapped terminals. | |
| SPP (2)<br>Makarand Nagle | NERC should provide, as a part of the standard, the loadability verification spreadsheet(s) and technical exceptions documentation it wants for documentation purposes. There may be many differing opinions on what documentation is acceptable. However, NERC should have created forms/spreadsheets/papers for completion that satisfy their documentation for loadability requirements.<br>Although SPP agrees with the need for a protection loadability standard, we believe this standard should apply to only 345kV and above systems. Most companies with 345kV and above have a larger impact on wide area/multi-state blackouts. Although the 100 to 200 kV systems may be critical to a localized region, loss of those voltages will probably not spread into a multi-state blackout, provided the 345kV and above systems remain in service. There are other regional requirements for loading and line ratings that probably suffice for the localized regions. |
| Response: (1) The SDT does not want to be overly prescriptive in specifying entity documentation.<br>(2) In some areas of North America, 138 kV, 161 kV, 230 kV, or other similar voltage class lines are very critical to the reliability of the BES, and need be considered. In other areas, with extensive higher-voltage transmission systems, these systems have the characteristic of high-voltage distribution lines. | |
| Pepco Holdings, Inc. Affil. (1)<br>Richard Kafka | See SPCTF comments. |
| Response: See response to SPCTF comments. | |
| Minnkota Power Coop, Inc. (1, 3, 5) – Tim Bartel | Using this one-size-fits-all approach for out-of-step blocking / tripping relays would prevent proper application in some situations. Orderly system separation following major events may require higher impedance out-of-step blinder settings than would be allowed by the standard.<br><br>Perhaps this is allowed for by the reference to "stable power swings" in section 1.2.3 of Attachment A, but it is not clear if this is the case. |
| Response: Where out of step tripping or blocking relays are applied independently within the system they must comply with the standard. However, when the out of step tripping or blocking relays are a part of a Special Protection Scheme (SPS), the SPS should be reviewed per the applicable NERC standards. | |
| Hydro-Québec TransÉnergie (1) – Roger Champagne | Hydro-Québec TransÉnergie (HQTÉ) is concerned about the Applicability of the standard (section A 4.1). It appears the standard applies to elements based solely on their voltage level.<br>It should be clarified that the standard applies only to BPS equipments. As a member of NPCC, HQTÉ have been using a performance based criteria to determine such equipments rather than using the voltage level.<br>HQTÉ has also an issue about some specific application of the standard.<br>In particular, for a portion of our 315 kV system, the standard as written cannot be complied with for technical reasons due to the system characteristics. We had to apply for technical exception. |

| Question #7 – Other comments on the standard? | |
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| | Also, in relation to the hot spot winding protection for all 735 kV transformers, HQTÉ practice for overloading those transformers imposes additional safety margins than what is proposed in IEEE C57.91 -1995. Again, HQTÉ will have to apply for technical exception.<br><br>These technical exceptions will not affect the reliability of the system.<br><br>The standard should be less specific to allow for such technical conditions. If technical exceptions are permitted, this should be indicated in the standard.<br><br>HQTÉ suggest the addition of two more elements in item 1.2 of Attachment A:<br>1) Relay elements associated with DC lines<br>2) Relay elements associated with transformers at converter station. |
| Response: The facilities to which the standard applies were selected to be consistent with the previous relay loadability activities within NERC. The technical exceptions available under the previous activities have been restated within the standard as criteria for demonstrating compliance. If none of these specific criteria apply, then R1.13 is available to establish study based compliance.<br>The suggested elements were added to Attachment A | |
| SERC PCS<br>Susan Morris | Regarding Levels of Non-Compliance, we would suggest that the criteria for Level 3 and the criteria for Level 4 should be exchanged. A violation resulting in a Reportable Disturbance seems to be more serious than "no evidence exists to support that relays comply with one of the criteria …". The existing Level 3 should also be "causal or contributory" instead of just "causal". It would also seem that a non-compliance with the relay loadability criteria (either evidentiary or on the physical relay) , whether causal to a Reportable Disturbance or not, should be identified within the Levels of Non-Compliance. Perhaps, this should be reflected by "Evidence indicates that relay settings do not comply with R1.1 through R1.13." as a Level 4 non-compliance.<br><br>Requirements section:<br>Reference the last sentence of R1. "The relay performance shall be evaluated at 0.85 per unit voltage and a power factor angle of 30 degrees." We suggest that this sentence should more clearly state that it applies only to relays that are sensitive to voltage or power factor angle.<br><br>R1.3.1 and R1.3.2 The calculation of maximum power transfer at 1.0 per unit is inconsistent with the use of 0.85 per unit voltage for relay load limit.<br><br>R1.5 More explanation should be included in this requirement. The present wording is somewhat ambiguous as to the intent, and more detail should be included to avoid confusion. |

| Question #7 – Other comments on the standard? | |
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| | R1.6 The standard and the reference document need to limit the application of this criteria on multiple lines out of a generation center to a 3 line situation. While it is agreed that the 3 line situation where 2 lines become outaged is foreseeable (i.e. one line is out for maintenance and a fault occurs on the second line), applying this scenario to more multiples becomes more and more unlikely.<br><br>R1.9 It seems R1.7 is covered under R1.9. Please explain why both are needed.<br><br>R2 R2.1 and R2.2 appear redundant. R2 already states approval is required from Regional Reliability Organization and Reliability Coordinator. The relay load limits should be included in all facility ratings. |
| Response:<br>The 'levels of non-compliance' were all replaced with 'violation severity levels' to conform to the ERO Rules of Compliance. While 'levels of non-compliance' were based on reliability-related risk of violating a requirement, violation severity levels identify how big the gap was between actual and required performance irrespective of the impact on reliability.<br>R1 - The drafting team feels that this clarification is unnecessary. If a relay is not sensitive to these quantities, it should be clear that they need not be considered. R1.31 and R1.3.2 - The 1.0 per unit voltage is based on converting the maximum power transfer to amps. The 0.85 per unit voltage is based on measured voltage during extreme operating conditions.<br>R1.5 – The standard provides a concise statement of the requirement. For the basis of the requirement and supporting material, please see the reference document.<br>R1.6 – The conservative nature of this requirement is intentional. The probability is low but the impact is high.<br>R1.9 and R1.7 - While the requirements may seem similar, the requirements address different topology.<br>R2 - "Approval" has been replaced with "Agreement", to reflect that the RC will adopt these loadability restrictions as the Facility Rating. R2.1 and R2.2 were combined. | |

### Attachment 1 – Supplementary Comments

### Comments on NERC Line Loadability Standard PRC-023 Reference

Most WECC members are well aware of the problem of setting zone 2 or zone 3 distance relays on long transmission lines with enough reach to adequately protect the line without violating NERC recommendation 8A. The problem arises because the thermal current limit of a line is independent of the lines length and does not change for a given conductor size no matter how long it is. The impedance of the line, however, increases with the lines length. As the line length and impedance increases, the reach of the distance relays that protect the line must also increase to provide adequate protection, until at some point the relay setting would operate for the maximum thermal current. This creates the dilemma of how to protect such a long line without limiting its load carrying ability.

On the other hand, as the line length and impedance increases, the ability to transfer power across the line diminishes until a point is reached where the maximum possible power transfer is less than the rated thermal power transfer limit. Using this diminished power transfer capability instead of the thermal limit as the basis of setting the reach of the distance relays should allow for a longer relay reach that will hopefully provide adequate protection for the line.

Requirements R1.3.1 and R1.3.2 of NERC Standard PRC-023-1, and as detailed in the *PRC-023 Reference*, attempt to allow the use of the maximum power transfer capability of a line to justify the use of relay settings that will operate at loads less than the line's thermal rating. While this approach has merit, I have the following concerns:

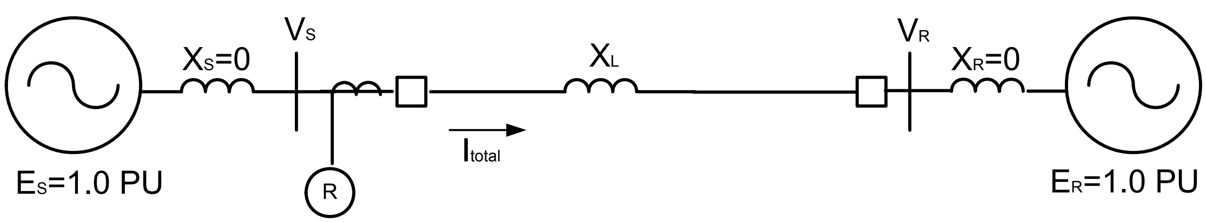
1) R1.3.1, correctly applied, will not justify a mho characteristic relay reach at the line impedance angle greater than 100% of the line impedance, and therefore, is not useful.

2) R1.3.2 offers little improvement over R1.3.1 and is not likely to justify the necessary reaches of zone 2 or 3 relays on very long lines.

3) The impedance seen by a relay is a constant percentage of the line impedance for any given power angle. This can be used to determine the maximum acceptable relay reach for any power angle. This may be useful to justify practical limits for relay reach.

Following is my explanation of the above concerns.

#### 1) R1.3.1 Does Not Justify Relay Reaches Greater Than 100% of the Line Impedance




R1.3.1 attempts to determine a relay reach based on the maximum theoretical power flow across a line that occurs when the power angle, δ, is 90°.

From R1.3.1 of the *PRC-023 Reference*, page 4:

$I_{total} = (V_{LL}\sqrt{2})/(X_L\sqrt{3})$

The impedance seen by the relay is:

$Z_R = V_{LG}/I_{total}$ where $V_{LG}$ is the line-to-ground voltage and $V_{LG} = V_{LL}/\sqrt{3}$ under balanced load

$Z_R = (V_{LL}/\sqrt{3}) / [(V_{LL}\sqrt{2})/(X_L\sqrt{3})]$

$Z_R = X_L/\sqrt{2}$

So the impedance seen by the relay, $Z_R$, is independent of the bus voltage during a maximum power transfer condition. If the voltage sags, the maximum possible power transfer across the line will also drop, and the impedance seen by the relay will remain constant.

Under the conditions assumed in R1.3.1, $|V_S| = |V_R|$ and the angle between $V_S$ and $V_R$ (power angle, δ) is 90°, the current through the line, $I_{total}$ will lag the voltage at the sending end by 45°, and the impedance seen by the relay, $Z_R$ , will be at 45°. Converting this to the maximum allowable reach for a mho characteristic relay at the line angle of 90° gives:

$Z_{90} = Z_R / \cos(90°-45°) = (X_L/\sqrt{2}) / \cos 45° = X_L$

The result shows that for a mho characteristic distance relay, the maximum power transfer approach will never justify setting the reach of a mho characteristic beyond 100% of the line impedance. Stated another way, at the maximum theoretical power transfer, a mho-characteristic distance relay with a reach equal to 100% of the line impedance at a maximum torque angle of 90° will pick up on load.

The results derived in R1.3.1 are slightly different because two safety factors are introduced. The first a voltage factor of 0.85 isn't necessary because, as shown above, the impedance seen by the relay is unaffected by the voltage when the maximum power transfer approach is used. The second safety factor increases the current by 1.15 which results in a reduced allowable relay reach of 1/1.15 or 87%.

Even with the safety factors, the impedance allowed by R1.3.1 is still larger than the value derived above ($Z_{90} = X_L$) because R1.3.1 incorrectly recommends that the impedance derived from the maximum power transfer equation be applied at a power factor angle of 30° instead of 45°. From R1.3.1:

$Z_{relay30} = (0.85V_{LL}) / (1.15 \cdot I_{total}\sqrt{3}) = (0.85/1.15)(V_{LL} \cdot X_L\sqrt{3})/(V_{LL}\sqrt{2}\sqrt{3})$

$Z_{relay30} = (0.85/1.15)(X_L /\sqrt{2}) = 0.739X_L/\sqrt{2}$

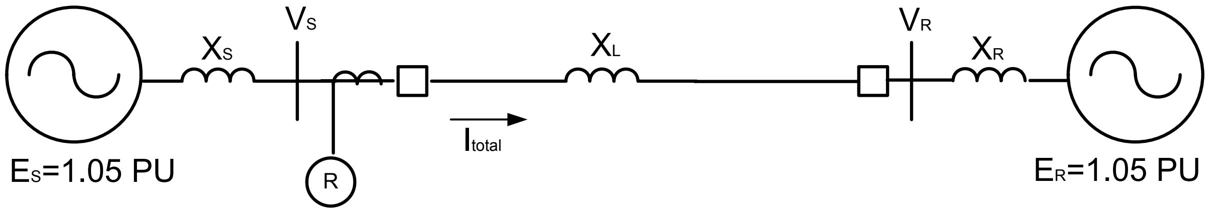
The maximum allowable reach for a mho characteristic relay at the line angle of 90° is:

$Z_{90} = Z_{relay30} / \cos(90°-30°) = (0.739X_L/\sqrt{2}) / \cos 60°$

$Z_{90} = 1.045 \cdot X_L$

So, the use of a 30° power factor angle as recommended in R1.3.1 offsets the safety margins that were applied and allows a slightly longer distance relay reach of 104.5% of the line impedance. This is not enough reach for a zone 2 relay to provide adequate protection for the line. The maximum power transfer approach, as used in R1.3.1, is useless in justifying adequate zone 2 settings for long lines!

**2) R1.3.2 Offers Little Help Over R1.3.1**




R1.3.2 uses the source impedances of the system to obtain a reduced maximum theoretical power flow at the power angle, δ, of 90°, and therefore a longer allowable relay reach than obtained by R1.3.1

From R1.3.2 of the *PRC-023 Reference*, page 6:

$I_{total} = (1.05V_{LL}\sqrt{2}) / [(X_S + X_R + X_L)\sqrt{3}]$

$Z_{relay30} = (0.85V_{LL}) / (1.15 \cdot I_{total}\sqrt{3}) = (1/1.05)(0.85/1.15)(X_S + X_R + X_L)/\sqrt{2} = 0.498(X_S + X_R + X_L)$

This is the same impedance seen by the relay as derived in R1.3.1 with $X_L$ replaced by $(X_S + X_R + X_L)$ and the result divided by 1.05 because of the 1.05 P.U. source voltage used.

The maximum allowable reach for a mho characteristic relay at the line angle of 90° is:

$Z_{90} = Z_{relay30} / \cos(90°-30°) = 0.498(X_S + X_R + X_L) / \cos 60°$

$Z_{90} = 0.996(X_S + X_R + X_L)$

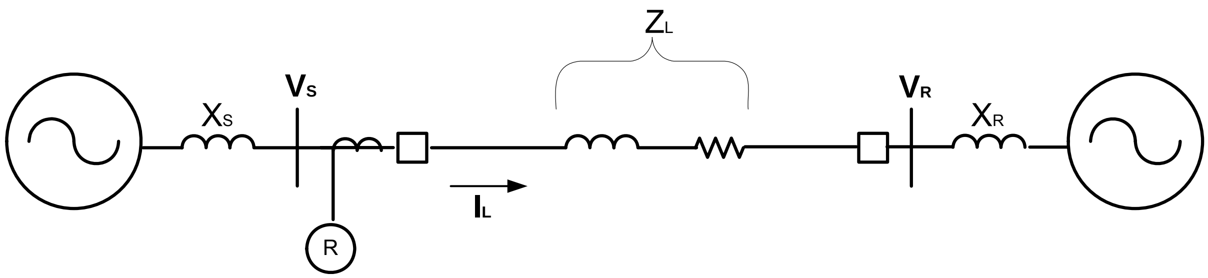
This shows that the maximum allowable reach of a mho characteristic relay at the line angle is approximately equal to $(X_S + X_R + X_L)$.  This method will only allow a mho characteristic relay to overreach the line impedance by the same percentage that $X_s + X_R$ is to the line impedance $X_L$.

$Z_{90} = 0.996 \cdot X_L\,[1+ (X_R + X_S)/X_L]$

In order to justify setting a zone 2 relay at the standard 125% of the line impedance with this method, $X_S + X_R$ must equal 25% of $X_L$.  For many long lines the source impedance at the terminals will not equal 25% of the line impedance and this method will not justify a mho characteristic reach that provides adequate line protection.

As in R1.3.1, R1.3.2 applies the relay reach at a power factor angle of 30° instead of the correct angle of 45°.  Using 45° results in even less allowable relay reach.

**3) Another Approach**




From the above diagram where $\mathbf{V_S}$ is the phase-to-ground voltage at the sending end, and $\mathbf{V_R}$ is the phase-to-ground voltage at the receiving end:

$\mathbf{V_S} = V_S\angle\Theta_S$ and $\mathbf{V_R} = V_R\angle\Theta_R$

$\mathbf{I_L} = (V_S\angle\Theta_S - V_R\angle\Theta_R) / Z_L\angle\Theta_L$

The impedance seen by the relay, $Z_R$, is:

$Z_R = \mathbf{V_S} / \mathbf{I_L} = V_S\angle\Theta_S / [(V_S\angle\Theta_S - V_R\angle\Theta_R) / Z_L\angle\Theta_L]$

$Z_R = Z_L\angle\Theta_L \cdot V_S\angle\Theta_S / (V_S\angle\Theta_S - V_R\angle\Theta_R)$

If the receiving end voltage is used as the reference, $\Theta_R = 0°$ and the power angle $\delta = \Theta_S - \Theta_R = \Theta_S$. If the magnitude of the sending- and receiving-end voltages are equal, $V_R = V_S$, and we get:

$Z_R = Z_L\angle\Theta_L \cdot V_S\angle\Theta_S / (V_S\angle\Theta_S – V_S\angle 0°)$

$Z_R = Z_L \cdot V_S\angle(\Theta_S+\Theta_L) / V_S(1\angle\Theta_S – 1)$

$Z_R = Z_L \cdot 1\angle(\Theta_S+\Theta_L) / (1\angle\Theta_S – 1)$

This shows that the impedance seen by the relay, $Z_R$, is dependent only on the difference in angles between the sending and receiving end voltages and the magnitude and angle of the line impedance. The following table shows some values of $Z_R$ for different values of $\Theta_S$ when the line impedance angle, $\Theta_L$ , is 90°. The far right column shows the corresponding relay reach at 90° for a mho characteristic distance relay ($Z_{R90} = Z_R/\cos[90°-\Theta_{ZR}]$).

| $\Theta_S$ | $Z_R$ | Relay reach at line angle of 90° |
|---|---|---|
| 90° | $(0.707\angle 45°)\cdot Z_L$ | $1.0\cdot Z_L$ |
| 85° | $(0.740\angle 42.5°)\cdot Z_L$ | $1.095\cdot Z_L$ |
| 80° | $(0.778\angle 40°)\cdot Z_L$ | $1.210\cdot Z_L$ |
| 75° | $(0.821\angle 37.5°)\cdot Z_L$ | $1.349\cdot Z_L$ |
| 70° | $(0.872\angle 35°)\cdot Z_L$ | $1.520\cdot Z_L$ |
| 65° | $(0.931\angle 32.5°)\cdot Z_L$ | $1.732\cdot Z_L$ |
| 60° | $(1.00\angle 30°)\cdot Z_L$ | $2.00\cdot Z_L$ |

The table shows that in order to get a useful zone 2 reach of 125% or more of the line impedance, the power angle must be less than about 78°.

If the line impedance angle, $\Theta_L$ , is different than 90°, the allowable relay reach at the line angle will still be the same as that shown for a line angle of 90° in the table above. For example, the allowable relay reach for a line impedance angle of 80° on a system operating at a power angle of 75° gives:

$Z_R = Z_L \cdot 1\angle(\Theta_S+\Theta_L) / (1\angle\Theta_S - 1)$

$Z_R = Z_L \cdot 1\angle(75°+80°) / (1\angle 75° - 1)$

$Z_R = Z_L \cdot (0.821\angle 27.5°)$

The allowable relay reach at the line angle of 80° is:

$Z_{R80} = Z_L \cdot 0.821 / \cos(80°-27.5°)$

$Z_{R80} = 1.349 \cdot Z_L$

This is the same reach as the one in the table above for a power angle of 75°. This example can be applied to any line and power angle, and the above table can be generalized to:

| Power Angle δ | Mho Characteristic Relay Reach at Line Angle |
|---|---|
| 90° | $1.0 \cdot Z_L$ |
| 85° | $1.095 \cdot Z_L$ |
| 80° | $1.210 \cdot Z_L$ |
| 75° | $1.349 \cdot Z_L$ |
| 70° | $1.520 \cdot Z_L$ |
| 65° | $1.732 \cdot Z_L$ |
| 60° | $2.00 \cdot Z_L$ |

If we wanted to set a mho characteristic relay to reach 130% of the line impedance at the line angle ($Z_{LA}$) and allowed for a 15% overreach error, we'd have

$Z_{LA} = (1.15)(1.30)\ Z_L = 1.495 \cdot Z_L$

From the above table, the relay would not pick up on load until the power angle across the line exceeded 70°.

**Summary**

Trying to justify zone 2 and zone 3 relay reaches on long lines using the maximum power transfer capability of the line as described in R1.3.1 doesn't work. The method described in R1.3.2 will be very limited in its usefulness. A more useful approach would be to select a practical power angle less than 90° that is not exceeded during stable power system operation and base the maximum relay reach on that. Can a power angle of less than 90° be accepted as a practical limit that is unlikely to be exceeded in real-life operation? If so, a maximum relay reach, as a percentage of line impedance at the line angle, should be allowed for mho characteristic relays without further restrictions or justification. For example, if a 70° power angle is acceptable as a limit that is unlikely to be exceeded in stable operation, a relay reach at the line angle of 130% of the line impedance could be allowed without further restriction or justification. This could greatly reduce the number of relay settings requiring an exception to the standard.

**Response:**
While the cited requirements may be of minimal use for mho characteristic relays they have proven to be useful for other characteristic shapes.
The SPCTF, when developing the earlier activities, explored various power transfer angles for use within the requirements and discovered actual situations where the power transfer angles exceeded 80 degrees.