NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

# Consideration of Comments on Successive Ballot — Relay Loadability Order (Project 2010-13)

## Date of Successive Ballot: January 24 – February 14, 2011

**Summary Consideration:** A 20-day successive ballot was conducted for the Transmission Relay Loadability Version 2 standard PRC-023-2 from January 24, 2011 to February 14, 2011. The successive ballot achieved a quorum of 83.95% and a weighted segment approval of 65.71%. In addition to pointing out inconsistencies in the text of the PRC-023-2 standard, which the drafting team acknowledged and revised, commenters raised concerns in a few technical areas and the drafting team evaluated and responded to these concerns providing clarification and updates to the standard's text as noted below Some comments went beyond the scope of the project. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that the structure of the standard is unchanged from the approved PRC-023-1 and its requirements are consistent with the "Zone 3" and "Beyond Zone 3" reviews completed by industry following the August 14, 2003 Northeast Blackout. Suggested changes to the standard that require further modifications will be evaluated and added to the issues database for future consideration when making the next set of revisions to PRC-023.

Commenters expressed concern that (in the applicability section of the standard) the Regional Entity is being given additional authority to identify what equipment operating at or less than 100 kV is critical to the reliable operation of the grid. The drafting team noted that PRC-023 does not grant the Regional Entity any authority, rather it reflects language already contained in the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list entities that do not own or operate "a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity." However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES."

Commenters were also concerned about the selection of critical facilities according to the criteria in Attachment B and the apparent elimination of the facility owner's authority to determine which facilities are or are not included on the critical facilities list. The drafting team pointed out that an entity may confirm with their Regional Entity whether it has any circuits operated below 100 kV on a list of critical facilities. However, when circuits operated below 100 kV are identified on such a list, the Planning Coordinator is required to apply the criteria in Attachment B to the list of critical facilities to determine which circuits on the list are relevant to the reliability objectives of PRC-023-2 and for which the Facility owner must comply with PRC-023-2. This determination must (i) be based on technical studies or assessments and (ii) must be made in consultation with the Facility owner. While the drafting team understands the need for Facility owner input, it is also inappropriate to give the Facility Owner de facto veto power by using the phrase "upon mutual agreement with." The drafting team believes the Planning Coordinator will give due consideration to the Facility owner's input, and in cases where the Facility owner disagrees with the determination of the Planning Coordinator, an appeals process in Section 1700 of the NERC Rules of Procedure has been developed to address this concern.

Commenters raised concerns about the use of flowgates or permanent flowgates as a criterion to designate a facility as critical from a reliability perspective. The drafting team noted that the NERC Glossary states that "Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits." This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. To the extent that Flowgates are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates.

Commenters raised concerns regarding the removal of the reference to category C3 contingencies in Attachment B, criterion B4 of PRC-023-2, which includes the consideration of double contingency events without manual system adjustments between contingencies. The drafting team indicated that the purpose of the B4 criterion is to determine whether relays must be set to meet loadability requirements such that the circuits will

not be tripped prematurely, resulting in widening of the initiating outage if manual adjustments were not completed before the second contingency. The test identified in criterion B4 is consistent with, and developed specifically to address, the reliability concern driving the need for this standard. The drafting team notes that if manual adjustments were allowed between contingencies in criterion B4, this criterion would not identify any circuits subject to this standard except in cases where TPL-003 is violated. The test appropriately identifies circuits that may be loaded to levels that challenge relay settings when multiple contingencies occur. The drafting team also clarified that the reference to category C3 contingencies was removed since it resulted in confusion with some entities because the test required in criterion B4 is not the same as category C3, since criterion B4 does not include manual system adjustments between contingencies.

Some commenters indicated that there is confusion in the wording regarding Attachment A, Section 1.6 with respect to the listing of those protective functions that are within the scope of PRC-023-2 and requested clarification. The drafting team acknowledged this confusion and inserted parenthetical statements to clarify that the phrase “phase overcurrent supervisory elements” refers to phase fault detectors and “current-based communication-assisted schemes” refers to pilot wire, phase comparison, and line current differential schemes.

If you feel that the drafting team overlooked your comments, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

| Voter | Entity | Segment | Vote | Comment |
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| Kirit S. Shah | Ameren Services | 1 | Negative | (1) We do not agree with the implied establishment of ratings outside of the requirements of FAC-008 in Requirement R1, criterion 1, which implies the establishment of a 4 hour rating. Rather than specifically identify the duration, the term ‘highest seasonal long-term emergency’ rating should be used.<br><br>(2) Attachment B Criterion B1 still includes the consideration of flowgates. We believe that this criterion should be removed from Attachment B.<br><br>(3) Attachment B Criterion B4 includes the consideration of double contingency events without manual system adjustments between contingencies. While the specific mention of Category C3 contingencies is removed, which would permit limiting consideration of multiple contingency events to Category C1 bus fault, C2 breaker failure, and C5 common structure outages where no operator intervention would be possible, such contingency selection would be up to the Planning Coordinator, not the individual Transmission Owner. As written, the Facility owner would only have input as to the threshold level against which the post-contingency loading would be compared, rather than the selection of the multiple contingencies to be simulated. Any ‘N-1-1’ contingencies should be considered as congestion issues and should not be considered as part of the criteria in Attachment B for this |

[1] The appeals process is in the Reliability Standards Development Procedure: http://www.nerc.com/files/RSDP_V6_1_12Mar07.pdf.

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<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td></td><td>reliability standard.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.<br><br>1. The drafting team would understand this concern if the standard required that entities establish 4-hour ratings; however, the drafting team notes that this criterion intentionally refers to “the available defined loading duration nearest 4 hours” to make it clear that an entity is not required to develop a 4-hour rating. An entity may use an existing rating, for any time duration, so long as when multiple ratings are available an entity uses their existing rating that is based on a time duration nearest to 4 hours. This phrase has remained unchanged from the “Zone 3” and “Beyond Zone 3” reviews completed following the August 14, 2003 Northeast Blackout and is part of the approved standard PRC-023-1. The drafting team is not aware of any assertion that this criterion establishes a de facto requirement for entities to develop ratings based on 4-hour duration.<br><br>2. As noted in the NERC Glossary, “Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits.” This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. To the extent that Flowgates are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates.<br><br>3. The test identified in criterion B4 is consistent with, and developed specifically to address, the reliability concern driving the need for this standard. System disturbances in which relay loadability was a contributing factor, such as occurred on August 14, 2003, involve multiple contingencies without sufficient time for operator action. The drafting team notes that if manual adjustments were allowed between contingencies in criterion B4, this criterion would not identify any circuits subject to this standard except in cases where TPL-003 is violated. The test appropriately identifies circuits that may be loaded to levels that challenge relay settings when multiple contingencies occur. When such circuits are identified the Facility owner is required to meet relay loadability requirements to prevent the circuit from tripping unnecessarily before an operator has time to take corrective action. The drafting team respectfully points out that the Facility owner is not required to take any action to prevent overloads from occurring under such circumstances; the Facility owner is required only to provide relay loadability per the requirements in PRC-023 to mitigate the potential for such N-2 contingencies from leading to instability, uncontrolled separation, or cascading outages. The drafting team believes that assigning selection of contingencies to the Planning Coordinator, and requiring Planning Coordinator consultation with the Facility owners regarding evaluation of post-contingency loading, is consistent with the NERC Functional Model.</td></tr>
<tr><td>Paul B. Johnson</td><td>American Electric Power</td><td>1</td><td>Affirmative</td><td>The wording of Attachment A, section 1.6 should be made consistent to avoid any confusion. AEP suggests that it be reworded to read: "Supervisory elements used as fault detectors associated with pilot wire or current differential protection systems where the system is capable of tripping for loss of communications".</td></tr>
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| **Response:** Thank you for your comment.<br><br>The drafting team apologizes for confusion regarding Attachment A, Section 1.6 during the previous posting. The drafting team had intended to provide additional clarification. The drafting team has inserted parenthetical statements to clarify that the phrase "phase overcurrent supervisory elements" refers to phase fault detectors and "current-based communication-assisted schemes" refers to pilot wire, phase comparison, and line current differential schemes. We believe this modification is in-line with your recommended modification. | | | | |
| Andrew Z Pusztai | American Transmission Company, LLC | 1 | Affirmative | None |
| **Response**: Thank you for your support. | | | | |
| Donald S. Watkins | Bonneville Power Administration | 1 | Negative | 1. BPA believes that there is a major discontinuity in the logical flow of the standard. As described in Section 4.2, the standard applies to certain transmission lines and transformers. In Requirement R1, there are thirteen criteria to select from "for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions". Of these thirteen criteria, only two apply to transformers--number ten and eleven. The way that these two are buried in between the other criteria that apply to line terminals and the way that they are written creates a question as to whether they apply to all transformers or only to transformers that are part of a transformer-terminated line. Additionally, since they are part of the group of thirteen criteria, of which only one must be selected, it appears that criteria ten and eleven can be ignored if another criterion is selected for a transformer-terminated line. BPA forsees this issue causing enough confusion among auditors and transmission owners that we cannot vote in favor of the standard until it is remedied. It would clear up the confusion if Criterion 10 was separated into two parts: one part that deals only with transmission line relays for transformer-terminated lines, and a second part that deals with load-responsive transformer relays. The second part--that deals with load-responsive transformer relays--should be moved along with Criterion 11 into a new requirement. This way, all of the criteria in Requirement 1 will apply only to line relays, with only one of the criteria needed to ensure that the line relays will not limit transmission system loadability. The new requirement (suggest using R2 and bumping the other requirements up a number) would deal specifically with load responsive transformer relays. Because this requirement would not be |

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| | | | | intermingled among the 13 optional criteria of Requirement 1, it would be clear that all load responsive transformer relays--not just those for transformer-terminated lines--were required to comply.<br>2. The drafting team has cleared up a major issue with Criterion 10.1 of Requirement 1 by clarifying that load responsive transformer relays must not expose a transformer to fault levels and durations that exceed the transformers mechanical withstand capability. This makes the requirement achievable, while the earlier version, which required that the relays not expose a transformer to fault levels and durations that exceeded its capability, was not. However, the mechanical withstand capability is not a well defined value, and the drafting team's use of a footnote to clarify this requirement is not sufficient. BPA agrees with the use of IEEE C57.109-1993 as the best way to define mechanical withstand capability, but if this is to be used as the measure of this requirement, it should be written into the requirement and not merely mentioned as a footnote. In addition, Clause 4.4, Figure 4 of IEEE C57.109-1993, as mentioned in the footnote, applies only to Category IV transformers. A close look at the standard reveals that the mechanical withstand capability curves for the other categories are not the same, and the requirements for these other categories must be identified as well. |

**Response**: Thank you for your comments

1. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that the structure of Requirement R1 is unchanged from the approved PRC-023-1 and is consistent with the “Zone 3” and “Beyond Zone 3” reviews completed by industry following the August 14, 2003 Northeast Blackout. The drafting team provided additional clarity specific to criterion 10 by splitting the fault protection aspect directed in the order (now part 10.1) from the relay loadability aspects. The drafting team believes that combining portions of criteria 10 and 11 at this time would add confusion by intermingling fault protective relays and overload relays. However, the drafting team will include your recommendations in the issues database for future consideration in the next general revision of the standard.

2. The drafting team believes that because the reference does not establish a requirement, rather it defines the phrase mechanical withstand capability, it is most appropriately included as a footnote rather than within Requirement R1, criterion 10. The drafting team also believes that a general citing of IEEE C57.109 within the requirements would be problematic in that we are only referencing a portion of the standard. The drafting team notes that the mechanical withstand is well-defined within the standard and that a specific reference to Clause 4.4, Figure from IEEE C57.109-1993 referenced in PRC-023-2 is sufficient. Category IV transformers are defined as transformers over 10,000 kVA (10 MVA) single-phase or 30,000 kVA (30 MVA) three-phase. Since this standard applies to BES facilities, the drafting team believes that the vast majority (if not all) of the applicable transformers will be Category IV transformers; if any Category III transformers fall within the applicability of this standard, the associated mechanical characteristic is virtually identical.

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| Paul Rocha | CenterPoint Energy | 1 | Negative | For the Effective Dates for circuits identified by the Planning Coordinator pursuant to Requirement R6, CenterPoint Energy is concerned that, as PRC-023-2 is currently written, these identified circuits will be required to meet the loadability requirements even though planning-sponsored system improvements completed prior to the effective dates would alleviate inclusion of the circuit on the list. CenterPoint Energy would support Draft 2 if the wording “unless system changes, that alleviate inclusion of the circuit on the list, are completed before the applicable effective date is added to the end of 5.1.2.1 and 5.2.2.1. For example, 5.1.2.1 would be “The later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator of a circuit’s inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies, unless system changes, that alleviate inclusion of the circuit on the list, are completed before the applicable effective date.” |
| **Response**: The drafting team had intended that if a circuit identified in the near-term planning horizon no longer meets any of the criteria in Attachment B due to system improvements, the Facility would not be required to comply with the requirements of PRC-023 for that circuit. The drafting team has added a phrase to the end of 5.1.2.1 and 5.2.2.1 in the Effective Dates section to address your concern, although the drafting team has omitted the recommended reference to “system changes that alleviate inclusion of the circuit on the list.” This phrase was omitted to make the modification applicable to any reason for which the Planning Coordinator removes the circuit from the list before the applicable effective date. | | | | |
| Randall McCamish | City of Vero Beach | 1 | Negative | The Regional Entity is not the correct entity to make decisions concerning what < 100 kV equipment is critical or not. It is too subject to inconsistent criteria being applied across the continent. It also is not in alignment with the regulatory construct of a stakeholder process described in Section 215 of the Federal Power Act which affords us the opportunity to learn from each other and develop better answers and solutions that appropriately balance costs, benefits and risks. Development of criteria and the application of that criteria ought to be a collaborative process continent-wide such that the criteria are applied consistently across the continent. This can be done separately, or as part of the BES definition effort currently underway. In the interim, many regions have Planning Coordinators that are not self-regulating, e.g., the Planning Coordinator is separate from the asset owners. Most of the Planning Coordinators are stakeholder organization whose "Planning Committees" would make the determination. For entities that do self-regulate, e.g., they are both the asset owner and Planning Coordinator, presumably the Regional Entity could form a stakeholder process with a Planning Committee whose members include appropriate and balanced representation from the stakeholders. These "Planning Committees" could be an alternative source for a stakeholder process to determine criteria for < 100 kV Applicability and apply that criteria while a |

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| | | | | continent-wide effort is underway to determine that criteria. These "Planning Committees" could remain in place to apply the continent-wide criteria to the regional system. |
| **Response**: Thank you for your comment.<br><br>The drafting team notes that PRC-023 does not grant the Regional Entity any authority, rather it reflects language already contained in the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list entities that do not own or operate "a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity (emphasis added)." However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES." | | | | |
| Danny McDaniel | Cleco Power LLC | 1 | Negative | Section 4.2 establishes the conditions to ultimately include the entire electric power infrastructure under the umbrella of protecting the "bulk electric system" which was originally defined as 200kV and above. Cleco is concerned this ever expanding regulatory umbrella is not justified. |
| **Response**: Thank you for your comment.<br><br>The drafting team believes that Section 4.2 will identify only those circuits that if they trip due to relay loadability, may contribute to undesirable system performance similar to what occurred during the August 14, 2003 blackout. The criteria developed in Attachment B were developed to achieve this purpose.<br><br>To the extent the commenter is concerned with the reference to facilities operated below 100 kV, the drafting team points out that consistent with the FERC position in Order 733-A we expect that references to circuits operated below 100 kV will have narrow applicability. The drafting team also notes that to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this the reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES." | | | | |
| Robert Martinko | FirstEnergy Energy Delivery | 1 | Affirmative | We applaud the drafting team for their diligent and expeditious work on responding to the FERC directives of Order 733. We support the standard but ask that the team clarify the effective dates. Compliance Application Notice CAN-0013 which was recently posted for industry comment correctly adds clarification to the actual effective date for (1) Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System; (2) Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System; and (3) Switch-on-to-fault schemes on all applicable facilities. Since this CAN specifies the date of October 1, 2013 in the U.S., we ask that the following |

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| | | | | sections of PRC-023-2 be revised to include this date: "5.1.1.1.3 For switch-on-to-fault schemes as described in PRC-023-2 - Attachment A, Section 1.3, the later of the first day of the first calendar quarter after applicable regulatory approval of PRC-023-2 or the first day of the first calendar quarter 39 months following applicable regulatory (October 1, 2013 in the U.S.) approval of PRC-023-1; or in those jurisdictions where no regulatory approval is required, the later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011." and "5.1.2.1 The later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator (October 1, 2013 in the U.S.) of a circuit's inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies. |
| **Response**: Thank you for your comments.<br><br>The drafting team acknowledges the complexity involved in the effective dates for this standard. The drafting team has reformatted the Effective Dates section of the standard into a tabular format consistent with CAN-0013 and has inserted the US effective date (October 1, 2013) where appropriate. | | | | |
| Luther E. Fair | Gainesville Regional Utilities | 1 | Negative | The Regional Entity is not the correct entity to make decisions concerning what < 100 kV equipment is critical or not. It also is not in alignment with the regulatory construct of a stakeholder process described in Section 215 of the Federal Power Act which affords us the opportunity to learn from each other and develop better answers and solutions that appropriately balance costs, benefits and risks. |
| **Response**: Thank you for your comment.<br><br>The drafting team notes that PRC-023 does not grant the Regional Entity any authority, rather it reflects language already contained in the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list entities that do not own or operate "a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity (emphasis added)." However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES." | | | | |
| Harold Taylor, II | Georgia Transmission Corporation | 1 | Affirmative | The hyperlink on page 13 of the draft 3: January 21, 2011 does not work. Recommendation for future reference: Do not insert hyperlinks in documents. Instead, place recommended search words to be inserted into the "SEARCH |

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<tr><td></td><td></td><td></td><td></td><td>NERC.com" window. That is much less likely to become broken in the future.</td></tr>
<tr><td colspan="5">Response: Thank you for your comment.<br><br>The drafting team has updated the hyperlink and in consideration of your comment has updated the description of the reference document to facilitate a search if necessary.</td></tr>
<tr><td>Gordon Pietsch</td><td>Great River Energy</td><td>1</td><td>Negative</td><td>1. R1 Criteria 10.1 states that load responsive transformer fault protection relays should be set so that the settings do not expose the transformer to a fault current and duration that exceeds the transformer’s mechanical withstand capability. If load responsive protection needs to have its pickup increased due to not meeting R1 Criteria 10, this amount of load current should not be near the transformer’s mechanical withstand capability. We recommend that the drafting team add a Rationale Box or other supporting documentation that more clearly explains what the risks are.<br>2. In addition we are requesting an expanded description in Measure 1 on what exactly is required as evidence of calculations performed.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.<br><br>The drafting team agrees that it is possible to set fault protection relays to meet the relay loadability requirement in criterion 10 while coordinating the relay setting with the mechanical withstand capability. The explanation provided by the drafting team in response to comments on the previous posting would be an appropriate addition to the Reference Document posted with the standard.</td></tr>
<tr><td>Michael Gammon</td><td>Kansas City Power & Light Co.</td><td>1</td><td>Negative</td><td>1. The criteria with Attachment B is not consistent with the TPL planning standards and is likely to identify transmission facilities that do not pose a reliability threat to the operation of the interconnection. The criteria in Attachment B should focus on identifying transmission facilities that play a reliability role in maintaining equipment loadings within SOL and IROL facility ratings and not include other considerations such as flowgates which are a mechanism for energy market management.<br>2. In addition, the implementation time frames specified are not clear whether the implementation time frame of 24 months is an extension from the 18 month time frame for the RC to identify circuits using the criteria in Attachment B or if the 24 months is concurrent with the 18 months. Also, it is uncertain whether the 24 months will be sufficient without knowing the impact of the RC analysis.</td></tr>
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| **Response**: Thank you for your comments.<br>1. The criteria identified in Attachment B are consistent with, and developed specifically to address, the reliability concern driving the need for this standard. The drafting team continues to believe that Flowgates addressing reliability concerns for loading of circuits is an appropriate inclusion in these criteria. As noted in the NERC Glossary, "Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits." This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. To the extent that Flowgates are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates.<br>2. The drafting team believes the commenter is referring to the time provided to a Facility owner to comply with PRC-023 after the Planning Coordinator identifies a circuit is subject to PRC-023-2 per application of Attachment B. The drafting team notes that in the previous posting of the standard this timeframe was extended from 24 months to 39 months. Specific to the commenter's question, the standard identifies the 39 months are measured from "notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B." The 39 months in neither concurrent with nor an extension of the 18 months provided to the Planning Coordinator. | | | | |
| Stan T. Rzad | Keys Energy Services | 1 | Negative | The Regional Entity is not the correct entity to make decisions concerning what < 100 kV equipment is critical or not. It is too subject to inconsistent criteria being applied across the continent. It also is not in alignment with the regulatory construct of a stakeholder process described in Section 215 of the Federal Power Act which affords us the opportunity to learn from each other and develop better answers and solutions that appropriately balance costs, benefits and risks. Development of criteria and the application of that criteria ought to be a collaborative process continent-wide such that the criteria are applied consistently across the continent. This can be done separately, or as part of the BES definition effort currently underway. In the interim, many regions have Planning Coordinators that are not self-regulating, e.g., the Planning Coordinator is separate from the asset owners. Most of the Planning Coordinators are stakeholder organization whose "Planning Committees" would make the determination. For entities that do self-regulate, e.g., they are both the asset owner and Planning Coordinator, presumably the Regional Entity could form a stakeholder process with a Planning Committee whose members include appropriate and balanced representation from the stakeholders. These "Planning Committees" could be an alternative source for a stakeholder process to determine criteria for < 100 kV Applicability and apply that criteria while a continent-wide effort is underway to determine that criteria. These "Planning Committees" could remain in place to apply the continent-wide criteria to the regional system. |

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<tr><td colspan="5">Response: Thank you for your comment.<br><br>The drafting team notes that PRC-023 does not grant the Regional Entity any authority, rather it reflects language already contained in the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list entities that do not own or operate “a transmission element below 100 kV associated with <u>a facility that is included on a critical facilities list that is defined by the Regional Entity</u> (emphasis added).” However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are “part of the BES.”</td></tr>
<tr><td>Joe D Petaski</td><td>Manitoba Hydro</td><td>1</td><td>Negative</td><td>Please see comments previously submitted by Manitoba Hydro regarding<br><br>1. the effective date and<br>2. the items included in Section 1.6 of Attachment A.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.<br><br>1. The drafting team has considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1. Extending the timeframe included consideration of the number of circuits that may be identified by the Planning Coordinator.<br><br>2. Items included in Section 1.6 of Attachment A are included to address the concerns noted by FERC in Order 733. Settings for the protection schemes of concern are often very sensitive – well below load current – and dependent on the integrity of the communication channel to make a trip/no trip decision where other telecommunication system technologies require the operation of other protection system elements (usually distance elements) which are already subject to the requirements of this standard. Therefore, they will trip immediately due to load current upon the loss of communications, and are dependent on the fault detectors to inhibit trip which must therefore be secure regardless of how infrequently loss of communications may occur.</td></tr>
<tr><td>Terry Harbour</td><td>MidAmerican Energy Co.</td><td>1</td><td>Negative</td><td>1. The Attachment B5 criteria determining critical facilities appears to be wide open and eliminates the facility owner’s authority to determine what are and are not “critical” facilities on its own system based upon wording in Attachment B. The word “critical” is used throughout other NERC standards and has many potential implications. To give one entity, the Planning Coordinator, the power to assign the designation of “critical” potentially over a facility owners objection based upon any study or study criteria the Planning Coordinator decides is valid is inappropriate. Criteria B5 should be deleted. If B5 is not deleted, a minimum, the B5 wording “in consultation with” should be replaced with “upon mutual agreement with”. The facility owner who best understands its facilities should have some final say in conjunction with its Planning Coordinator in determining what is and is not critical to its system and the region.<br>2. The drafting team change in Attachment B1 of adding the word “permanent” in</td></tr>
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| | | | | front of “flowgate” did not correct the fundamental issue that a “flowgate” is not by definition a reliability issue and has no more measurable risk than the loss of any other BES transmission element. An example is the loss of a 161 kV flowgate, might have less reliability impact than the loss of a 345 or 500 kV line that is not designated as a flowgate. Therefore the criteria to define a “critical” facility through a flowgate designation is fundamentally in error. A better definition of “critical” is if the loss of a transmission element results in instability, uncontrolled separation, and cascading as defined in the Federal Power Act. |

**Response**: Thank you for your comments.

1. The authority for identifying circuits below 200 kV for which Facility owners must comply with PRC-023-2 is assigned to the Planning Coordinators in PRC-023-1. The drafting team believes that criterion B5 in Attachment B of PRC-023-2 is not wide-open because it requires that the determination must (i) be based on technical studies or assessments and (ii) must be made in consultation with the Facility owner. While the drafting team understands the need for Facility owner input, we also believe it is inappropriate to give the Facility Owner de facto veto power by using the phrase “upon mutual agreement with.” We believe the Planning Coordinator will give due consideration to the Facility owner’s input, and in cases where the Facility owner disagrees with the determination of the Planning Coordinator they are free to use the appeals process in Section 1700 of the NERC Rules of Procedure that was developed to address this concern.

2. As noted in the NERC Glossary, “Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits.” This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. To the extent that Flowgates are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates.

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| Richard Burt | Minnkota Power Coop. Inc. | 1 | Negative | 1. 115 kV lines should be included based on the impact they will have on the bulk system if they trip. Appendix B calls for them to be included if their risk of overload is above a threshold, regardless of their value to the bulk system. MPC's 115 kV transmission in northwest Minnesota has 3 principal 230 kV sources. With two of them outaged per the procedure in Appendix B, we may very well overload the third source. However, the risk is primarily to the load served by that 115 kV system, not the surrounding bulk system. By the procedure in Appendix B (B4a), the 115 kV sources would probably need to meet the standard, but they should not have to, due to the fact that the at-risk load is contained within the 115 kV system.<br>2. There are several places where the standard mandates how entities go about protecting their equipment so that it is not put at risk. R1 Criteria 10.1 and the related measurement M1 is an example. This goes beyond the reach of NERC. It |

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| | | | | is the entity's' prerogative how to protect its equipment.<br>3. R1 Criteria 5 needs further explanation.<br>4. R1 Criteria 6 seems too vague. Is it only to be applied to generation that has one radial tie to the bulk system? What if the generation is injected in the middle of a long line with no local load, so there are in essence two outlets?<br>5. In R1 Criteria 12, it appears that the 87% margin should be based on MVA, not current. Basing it on current appears to compromise the margin. |
| **Response**: Thank you for your comments.<br>1. The Purpose stated in PRC-023 includes ensuring that protective relay settings do not interfere with system operators' ability to take remedial action to protect system reliability. While the August 14, 2003 Northeast Blackout was the primary motivation behind development of the standard, the reliability objective of the standard is not limited to preventing wide-area outages. Smaller scale outages may impact system reliability and the criteria in Attachment B were developed specifically to address the reliability objective of this standard. The drafting team believes the criteria in Attachment B will identify circuits that are relevant to the reliability objective of PRC-023-2; however, as directed in ¶97 of Order 733, NERC has developed an appeals process so that Facility owners may challenge the determination of the Planning Coordinators. The appeals process will be contained in Section 1700 of the NERC Rules of Procedure.<br>2. The standard does not mandate how entities are to protect their equipment. The standard is limited to establishing relay loadability requirements to prevent circuits from tripping unnecessarily before an operator has time to take corrective action to mitigate the potential for instability, uncontrolled separation, or cascading outages. In the case of criterion 10.1, the standard does not require the use of load responsive transformer fault protection relays, it only requires coordination with the mechanical withstand capability of the transformer. How this coordination is achieved is up to the Facility owner.<br>3. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that Requirement R1, criterion 5 is unchanged from the approved PRC-023-1. Additional explanation is provided in the Reference Document posted with standard PRC-023-1.<br>4. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that Requirement R1, criterion 6 is unchanged from the approved PRC-023-1. Additional explanation is provided in the Reference Document posted with standard PRC-023-1.<br>5. Equipment thermal ratings are based on current rather than MVA. Applying the margin to the calculated current is correct as stated. | | | | |
| Saurabh Saksena | National Grid | 1 | Affirmative | 1. List of Critical Facilities: Since a critical facilities list would be prepared for other reasons (e.g. CIP-002), National Grid is assuming that the list of critical facilities will be reviewed for applicability to PRC-023 and that a subset of the list may need to be defined for this application.<br>2. There appears to be inconsistency in the wording pertaining to the sentence - "critical facilities list defined by the Regional Entity and selected by the Planning Coordinator". In 4.2.1.3 the aforementioned sentence is produced in its entirety. |

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| | | | | However, in attachment B, under Circuits to Evaluate, bullet point 2, the sentence is missing "...and selected by the Planning Coordinator". This piece is also missing in 4.2.2.2.<br>3. Attachment B, B4 a.: National Grid requests the drafting team to explain the rationale behind deleting "Category C3" from B4. National Grid believes that by providing reference to Category C3, the standard focuses on the scope and provides for consistency in the engineering judgment. However, by deleting Category C3, the scope becomes undefined as to the level of combinations that need to be assessed and will concern the engineer that his engineering judgment can be called into question.<br>4. Summary consideration on pg. 1 regarding supervisory elements associated with current based, communication assisted schemes having to meet PRC-023-2 and inclusion of such elements in Attachment A, 1.6: This is taken to mean line differential schemes. If the supervisory elements for a line diff must be set high enough to comply with PRC-023-2 that will make the entire scheme extremely insensitive to faults. For example R1.1 would require the supervising elements be set > 1.5 x the 4 hr. loading meaning the scheme will be unable to detect an internal fault unless it exceeds 1.5 x the 4 hr. loading. That negates one of the chief advantages of using a line differential scheme in the first place, specifically it's sensitivity. If the communications for a relay scheme is lost the scheme is essentially "broken" and to require it to still function correctly per PRC-023-2 even when broken is unreasonable. There is no requirement that distance schemes conform to PRC-023-2 if they are broken, for example if they lose their restraint potential they will trip on load too.<br>5. Switch on to fault scheme included in Attachment A, 1.3 - An exception needs to be added for those schemes that are smart enough to detect a live line condition and which are disabled when closing or reclosing into an already energized line. Such schemes will not respond to current flow into and through a live line. Requiring that such a SOTF scheme that can recognize a live line be set to carry through current regardless, negates the advantage of the scheme in the first place, specifically its sensitivity.<br>6. Regarding R1, Criterion 10 - What if the transformer at the end of the line has its own overcurrent protection that either trips a local high side breaker or circuit switcher or TT's the other end of the source line and this transformer overcurrent protection is set below the mechanical damage curve. Must the line protection back at the source to the line still be set below the transformer's mechanical damage curve? If your answer is yes, what if the line protection is step distance with a flat timer, like a zone 2 timer. Coordinating a zone 2 |

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| | | | | looking into the transformer and having a flat zone 2 timer against and inverse transformer mechanical damage curve is awkward at best and maybe not even feasible.<br>7. Regarding R1, Criterion 5 - "Weak source system" is a relative term. Is the reader free to define "weak" as the reader chooses? If not then it needs to be defined in the standard. |

**Response**: Thank you for your comments.

1. Yes, additional screening will be applied. The Planning Coordinator is required to apply the criteria in Attachment B to these facilities to identify which circuits on the list are relevant to the reliability objective of PRC-023-2.
2. These differences are intentional. Where the phrase is not included it is referring to the circuits that must be evaluated by the Planning Coordinator. The Planning Coordinator must apply the criteria in Attachment B to all facilities operated below 100 kV that are on a critical facilities list. However, the Facility owners are required to comply with PRC-023-2 only for those circuits selected by the Planning Coordinator in accordance with Requirement R6.
3. The reference to category C3 contingencies resulted in confusion with some entities because the test required in criterion B4 is not the same as category C3 since criterion B4 does not include manual system adjustments between contingencies.
4. Items included in Section 1.6 of Attachment A are included to address the concerns noted by FERC in Order 733. Settings for the protection schemes of concern are often very sensitive – well below load current – and dependent on the integrity of the communication channel to make a trip/no trip decision where other telecommunication system technologies require the operation of other protection system elements (usually distance elements) which are already subject to the requirements of this standard. Therefore, they will trip immediately due to load current upon the loss of communications, and are dependent on the fault detectors to inhibit trip which must therefore be secure regardless of how infrequently loss of communications may occur.
5. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that Attachment A, Section 1.3 is unchanged from the approved PRC-023-1. However, the drafting team will include your recommendations in the issues database for future consideration in the next general revision of the standard.
6. No, in the previous posting the drafting team separated the relay loadability aspect and the transformer fault protection aspect of criterion 10. The transformer fault protection relays and transmission line relays both must meet the relay loadability requirements listed in the two bullets in criterion 10. Only the transformer fault protection relays, if used, must be coordinated with the transformer mechanical withstand capability.
7. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that Requirement R1, criterion 5 is unchanged from the approved PRC-023-1. Entities may apply criterion 5 to any line, although when the source becomes sufficiently strong this criterion will become more restrictive than others.

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| David Thorne | Potomac Electric Power Co. | 1 | Negative | Attachment A of the standard provides a listing of those protective functions that would be in scope. Presently Section 1.6 of Attachment A is worded as "Supervisory elements associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communication." In our comments on the previous ballot we stated: " The intent of this section was to specifically address phase overcurrent supervising elements (i.e. phase fault detectors) associated with pilot wire, phase comparison, and line current differential schemes where the scheme is capable of tripping for loss of communications. However, we believe that the term “current-based communication-assisted schemes” is too generic and may be confusing without mention of the specific schemes to which this requirement applies....Therefore, to clarify the requirement we suggest replacing the current wording with either “Phase overcurrent supervisory elements (i.e. phase fault detectors) associated with pilot wire, phase comparison, and line current differential schemes, where the scheme is capable of tripping for loss of communications” or “Phase overcurrent supervisory elements (i.e. phase fault detectors) associated with current-based communication-assisted schemes (i.e. pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications”. The Standard Drafting Team (SDT) responded to our comment by stating "Attachment A applies to the listed protective functions that respond to load so it’s unnecessary to use the word “phase”. Section 1.6 has otherwise been modified essentially as you suggest in response to your comment." There was another similar comment from AEP with the same SDT response. The SDT did not modify Section 1.6 using either of our suggestions, since the wording in the current version remains exactly the same as in the previous version. This may have been an oversight by the SDT. Without specific identification of what schemes are in scope, you are leaving up to an auditor to determine what schemes are "current-based" and what "supervising elements" are you talking about. |
| **Response:** Thank you for your comment.<br><br>The drafting team apologizes for confusion regarding Attachment A, Section 1.6 during the previous posting. The drafting team had intended to provide additional clarification. The drafting team has adopted your second proposal and has inserted parenthetical statements to clarify that the phrase “phase overcurrent supervisory elements” refers to phase fault detectors and “current-based communication-assisted schemes” refers to pilot wire, phase comparison, and line current differential schemes. | | | | |
| Catherine Koch | Puget Sound Energy, Inc. | 1 | Negative | 1. Puget Sound Energy believes this standard is structured in a way that will create confusion relative to required actions and timelines. For example; Section 4.2.1 Circuits Subject to Requirements R1-R5 This section refers to T-lines and transformers selected by the Planning Coordinator without any clear criteria to |

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| | | | | use for the selection which is impossible to comply to.<br>2. T-lines and Transformers below 100 kV are also applicable if they are included on a critical facilities list defined by the Regional Entity and selected by the Planning Coordinator. We have not seen this specific list and do not have any criteria for our own selection process, which makes this impossible to comply with.<br>3. Section 5. Effective Dates This section is confusing with 5 different effective dates which roll forward when any changes to the standard are made. These dates also refer to requirements which depend upon lists and selection criteria that have not been provided by the region.<br>4. Section PRC-023 Attachment B, Part B4.a, Circuit Identification Criteria "Simulate double contingency combinations selected by engineering judgment...." The words Engineering Judgment should not appear in any NERC standard. The committee chose to replace a reference to TPL 003 Category C3 which was at least something specific. It is impossible to meet compliance with something as vague as Engineering Judgment. |

**Response**: Thank you for your comments.

1. The criteria for selection by the Planning Coordinator in Applicability Sections 4.2.1.2 and 4.2.1.5 are the same as Sections 4.2.1.3 and 4.2.1.6. These two sections also should have included the phrase “in accordance with Requirement R6” and this clarification has been added. Thank you for identifying this discrepancy.

2. An entity may confirm with their Regional Entity whether they have any circuits operated below 100 kV on a list of critical facilities. When circuits operated below 100 kV are identified on such a list, the Planning Coordinator will be required to apply the criteria in Attachment B in accordance with Requirement R6 of PRC-023-2 to identify any circuits on the list for which the Facility owner must comply with PRC-023-2. To provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has replaced the reference to a “list of critical facilities” with a reference to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are “part of the BES”.

3. The drafting team acknowledges the complexity involved in the effective dates for this standard. The drafting team has reformatted the Effective Dates section of the standard into a tabular format to improve clarity.

4. The drafting team notes that similar to the Transmission Planning (TPL) standards, it is not reasonable to require simulation of every combination of contingencies nor is it possible to provide a bright-line to clearly define which contingencies must be simulated for every possible system topology. Some level of judgment is necessary to determine the double contingency combinations that must be simulated to meet the reliability objectives of the standard.

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| Dana Cabbell | Southern California Edison Co. | 1 | Negative | We do not feel that the concerns raised in comments on the last round of balloting have been adequately addressed. Among the concerns still remaining are the use of "critical facilities" in several of the requirements and the respective roles that Regional Entities and Planning Coordinators will play in identifying critical facilities. |
| **Response**: Thank you for your comments.<br><br>The Regional Entity may develop a list of critical facilities by means outside this standard. The reference to a list of critical facilities in PRC-023-2 is in the same context as the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list an entity that does not own or operate "a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity (emphasis added)." To provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has replaced the reference to a "list of critical facilities" with a reference to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES".<br><br>The role of the Planning Coordinator is defined in Requirement R6. The Planning Coordinator will be required to apply the criteria in Attachment B in accordance with Requirement R6 of PRC-023-2 to identify any circuits on the list for which the Facility owner must comply with PRC-023-2. | | | | |
| Larry Akens | Tennessee Valley Authority | 1 | Affirmative | Permanent flowgate" is too ambiguous. Most entities in the eastern interconnect use flowgates in many different processes such as EMS systems and state estimator, transfer capability calculations, congestion management processes, and market calculations. All of these processes have flowgates that could be considered "permanent". If this standard is pointing to the IDC Book of Flowgate (BOF) Permanent flowgates, then this should be so stated. However, since the IDC BOFs is not the most up to date list of flowgates, we suggest that a better line criticality identification to reliability is if a TLR has been called on the flowgate in the last two year. We recommend that instead of "permanent flowgate", the B1 portion of Attachment B1 should say " in the IDC Book of Flowgates and a TLR 3 or greater has been called on the flowgate in the last two years |
| **Response**: Thank you for your comments.<br><br>The drafting team appreciates the suggestion to further refine the Flowgates of interest in the context of criterion B1. However, the drafting team believes that the Flowgates of interest must be determined based on the reliability basis for adding the Flowgate rather than historical transfers. Even if a TLR has not been called on a Flowgate for an extended period of time, during a system disturbance an overload on a monitored Facility comprising the Flowgate could lead to cascading outages if relay loadability requirements are not met. The drafting team believes it is best to continue to refer to circuits that are monitored Facilities of Flowgates that are included to address reliability concerns for loading of those circuits. | | | | |

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| Keith V Carman | Tri-State G & T Association, Inc. | 1 | Negative | 1. The response to our concern about Requirement R1, Criterion 10 acknowledges that 150% of the highest rating of many transformers is 250% of the transformer's base rating. Since the transformer thermal damage curve begins at 200% of the base rating, this requirement can force entities to set relays that don't fully protect their transformers. Is Requirement R1, Criterion 13 intended to be used for those situations? We think it would be more appropriate to address the concern in Criterion 10 with language to indicate that if the loading requirement violates thermal protection, then the protection requirement rules and the relays should be set (with some reasonable margin) to allow as much loading as possible while ensuring no thermal damage.<br>2. With regard to requirements R4 and R5, we acknowledge the modifications of measures M4 and M5 that allows lists of incremental changes to be submitted. We believe M4 and M5 should be clarified that in the event of no changes, a submittal is not required or a submittal of "no changes" is acceptable. Periodic duplicate submittals are unnecessary and unique submittals would more easily identify the loadability issues that the operators need to consider. The FERC Order did not require annual submittals.<br>3. With regard to Attachment B criterion B4, we agree that it is a technically sound approach but we believe that existing TPL simulations and assessments should be utilized first to narrow the scope of the analyses. Afterwards, the new simulation that is described in criterion B4 can be implemented. An example would be if an element's loading exceeded 100% of its Facility Rating using the normal TPL assessment, then the assessment with no manual intervention would be applied and subsequent steps of criterion B4 would be followed.<br>4. With regard to Attachment B criterion B5, we acknowledge the modification that the Facility owner should be consulted. However, we believe that criterion B5 should be removed entirely. We believe that if criteria outside of those in B4 will be used, they should only be used if mutually agreed upon, which the new B6 expresses. We believe consultation alone does not prevent the criterion from being applied discriminatorily or differently even within the same interconnection. |

**Response**: Thank you for your comments.

1. Relays applied for transformer fault protection are subject to Requirement 1, criterion 10. As with any relays applied for fault protection, it may not be possible to provide thermal protection. Requirement R1, criterion 11 explicitly addresses relays applied for transformer overload (thermal) protection.
2. Measures M4 and M5 have been updated to indicate that "The updated list may be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list".

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| 3. The Planning Coordinator is free to apply the criteria in Attachment B in conjunction with analyses performed to demonstrate compliance with the Transmission Planning (TPL) standards to facilitate efficiency. One option would be for the Planning Coordinator to apply the tests as described in this comment. The drafting team believes it is best to allow this flexibility without prescriptive language that would lock a Planning Coordinator into any one approach.<br>4. The drafting team believes that criterion B5 in Attachment B of PRC-023-2 is appropriate because it requires that the determination must (i) be based on technical studies or assessments and (ii) must be made in consultation with the Facility owner. While the drafting team understands the need for Facility owner input, we also believe it is inappropriate to give the Facility Owner de facto veto power by using the phrase “upon mutual agreement with.” We believe the Planning Coordinator will give due consideration to the Facility owner’s input, and in cases where the Facility owner disagrees with the determination of the Planning Coordinator they are free to use the appeals process in Section 1700 of the NERC Rules of Procedure that was developed to address this concern. The situation covered by criterion B6 differs from criterion B5 in that mutual agreement is required in place of supporting technical studies or assessments. | | | | |
| Brandy A Dunn | Western Area Power Administration | 1 | Negative | 1. Section B Requirement R1 Criteria 10.1 This should be removed from the standard. As described in IEEE C57.109-1993, the mechanical damage portion of the curve applies to frequent faults over the life of the transformer. It may be necessary, in some cases and for some conditions, to set protective elements between the mechanical and thermal portion of the damage curve. In these cases, additional steps such as disabling or limiting automatic reclosing on neighboring circuits and/or utilizing Operational guidelines can be used to mitigate possible impacts. NERC should not direct this coordination issue but instead should leave it up to the Protection Engineer to provide a solution that fits the situation at hand.<br>2. Section B Requirement R1 Criteria 11 The second bullet refers to footnote 4 which refers to IEEE standard C57.115. IEEE standard C57.115 has been withdrawn for some time. The active standard is IEEE C57.91. The NERC standard needs to refer to active IEEE standards. If IEEE C57.91 does not support the statement of the second bullet under R1 11 then the NERC standard should be corrected. |
| **Response**: Thank you for your comments.<br>1. The drafting team disagrees with the commenter’s assessment. The mechanical withstand characteristic in IEEE C57.109 is specifically characterized as applying for "faults which occur infrequently ..." The IEEE Guide considers that thermal exposure (to frequent faults) is a phenomena for which the transformer will recover when the thermal condition is relieved, while mechanical exposure (to infrequent faults) will possibly cause immediate and irrecoverable damage when the transformer's capability is exceeded. While it is true that each entity should apply their engineering judgment as well as mitigating practices to the application of protective relays, NERC is responsible to establish standards to prescribe minimum practices which the entities must meet. The drafting team believes that the use of the mechanical withstand characteristic as proposed in Requirement R1, criterion 10, is an appropriate method of addressing this concern. | | | | |

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| 2. The drafting team appreciates identification of this issue. The reference has been changed to indicated that IEEE C57.91, Tables 7 and 8 specify that transformers are to be designed to withstand a winding hot spot temperature of 180 degrees C, and that Annex A cautions that bubble formation may occur above 140 degrees C. | | | | |
| Chuck B Manning | Electric Reliability Council of Texas, Inc. | 2 | Negative | Please reference December 2010 IRC comments. |
| **Response**: Thank you for your comment.<br><br>The drafting team has reviewed the previous comments and believes we have adequately addressed them within the standard or explained why modifications to the standard are not warranted. | | | | |
| Kim Warren | Independent Electricity System Operator | 2 | Affirmative | We thank the Drafting Team for responding to our comments on the previous posting. We make the following further suggestions.<br><br>1. The Applicability section now includes Section 4.2.2 - Circuits Subject to Requirement R6. These applicability statements are repeated in Attachment B with one change to the second bullet where "Transmission lines" has been replaced by "Lines". We believe this repetition is unnecessary and has led to inconsistency observed. In our view a simple reference to Section 4.2.2 would be sufficient.<br>2. The DT has introduced the phrase "one-to-five-year planning horizon" in Criterion B4. We suggest using the defined term "Near-Term Transmission Planning Horizon" that was developed as part of the recently balloted Project 2010-10: FAC Order 729. |
| **Response**: Thank you for your comments.<br><br>1. In the most recent posting the drafting team has eliminated much redundancy between the Applicability section, Requirement R6, and Attachment B. The drafting team acknowledges that repeating the applicability statements in Attachment B is redundant, but believes this limited amount of redundancy is beneficial in allowing a reader to obtain a complete understanding of the criteria in Attachment B without the need to refer back to the Applicability section. The drafting team has addressed the discrepancy identified by the commenter and appreciates identification of this issue.<br><br>2. The drafting team appreciates this suggestion, but is reluctant to refer to a defined term until it is included in the NERC Glossary. However, the drafting team will include your recommendation in the issues database for future consideration in the next general revision of the standard. If the term is approved at that time, we believe that making the recommended change would be appropriate. | | | | |

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| Kathleen Goodman | ISO New England, Inc. | 2 | Negative | Two issues still remain with this draft:<br>1. R1.2 still makes no sense and the SDT response did not seem to address our comment.<br>2. R4 this is a problem which wasn't in the last version that we commented on. Now, even if nothing changes, we are required to rerun everything. This seems a significant use of resources with no Reliability benefit. |
| **Response**: Thank you for your comments.<br>1. Requirement 1 was developed to prevent circuits from tripping unnecessarily before an operator has time to take corrective action. Recognizing that most entities do not utilize ratings for durations less than 4 hours, the initial criteria developed in response to the August 14, 2003 blackout was based on 150 percent of the Facility Rating nearest 4 hours. Criterion 2 was added to acknowledge that some entities do utilize a 15-minute rating, and that relay loadability in these cases may be based on this rating. This criterion provides an alternate method of meeting Requirement R1 when criterion 1 would result in an unrealistic relay loadability requirement (e.g. if a circuit had a 4-hour rating of 500 MVA and a 15-minute rating of 600 MVA, relay loadability may be based on 1.15 x 600 = 690 MVA instead of 1.5- x 500 = 750 MVA. In some cases this may be the difference between the Facility owner being able to reset the relays versus requiring a capital project to replace the relays. The drafting team notes that this criterion is unchanged from the “Zone 3” and “Beyond Zone 3” reviews completed following the August 14, 2003 Northeast Blackout and is part of the approved standard PRC-023-1.<br>2. The drafting team is confused by the comment since Requirement R4 does not require any analysis to be performed. The updated list referred to in this requirement is simply a list of circuits for which entities choose to use Requirement R1, criterion 2 to demonstrate relay loadability. The lists are developed by the Facility Owners and provided to the Planning Coordinator, Transmission Operator, and Reliability Coordinator.<br>If the comment is directed toward criterion B4 in Attachment B, the drafting team notes that the footnote explicitly clarifies that when no material changes occur, past analyses may be used to support the assessment. This removes the burden of repeating past studies to avoid unnecessary deployment of resources. | | | | |
| Jason L Marshall | Midwest ISO, Inc. | 2 | Negative | We appreciate the drafting team’s continuing efforts to refine the draft standard but believe there are still significant issues.<br>1. We continue to believe that flowgates should not be included in the criteria at all because they do not usually represent significant reliability issues that might cause instability, uncontrolled separation or cascading but in fact are primarily used to manage congestion and to sell transmission service. In response to our comments from the previous ballot, the drafting team indicated congestion and system reliability are not mutually exclusive. While we agree on this point, we disagree on some of their further points. They indicate that the transmission system is operated within the physical constraints of the transmission system to prevent instability, uncontrolled separation or cascading. This implies that all |

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| | | | | flowgates are associated with IROLs. This is in fact not the case and most flowgates are not associated with IROLs. Furthermore, the markets are often constrained to respect physical limitations such as equipment limits but many times these are not associated with instability, uncontrolled separation and cascading. The drafting team further indicates that the IDC is used to preserve system reliability. This is simply not the case. It is used to manage congestion in an equitable manner. The FERC in Order 693 specifically prohibited the use of the IDC to manage IROL constraints because it was not fast enough to prevent instability, uncontrolled separation and cascading outages. This was also cited in the August 2003 Blackout Report. Furthermore, this is reflected in IRO-006-4.1 R1.1. Criteria B2 will identify those circuits whose failure could lead to instability, uncontrolled separation and cascading outages obviating the need to include flowgates.<br>2. We do not support criterion B4. It exceeds what is required in the TPL standards and what is required per the reliability directive in Order 729. The TPL standards allow system operator intervention for category C3 contingencies between the two independent Category B contingencies. This standard should not exceed those requirements in the TPL standards. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test “must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning.” Paragraph 80 states that “the test must be consistent with the general reliability principles embedded in the existing series of TPL” standards. Thus, exceeding the TPL standards could be argued as deviating from the directive. We continue to believe that if the system as currently designed meets the performance requirements in TPL-003-0a R1 which allows for operator intervention on Category C3 contingencies, then the subject facilities would not be included in the PRC-023-2 R6 list of facilities. For those C3 contingencies that don’t currently meet the performance obligations after operator interventions, the subject facilities would be included in the PRC-023-2 R6 list of facilities.<br>3. We do not believe requirement R4 is needed. Limiting a relay setting to 115% of the associated transmission line’s highest seasonal 15 minute rating does not equate to a line that will trip before the operator has time to intervene. It does not mean the line will trip in 15 minutes. In fact, the operator should be taking action well in advance of reaching a 15 minute limit and the operator is likely only using the 15 minute rating in extreme circumstances. Furthermore, the |

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| | | | | operator will have more than 15 minutes to act with a setting 115% above the 15-minute rating.<br>4. We continue to believe PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. Contrary to the response of the drafting team to the last set of comments, the communication of facility ratings should include the time associated with the rating. Thus, if a facility is limited to 15 minutes or 30 minutes or any other finite amount of time, it should be included in the information communicated about facility ratings. Because FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator, this information regarding the time associated with the limitation should be communicated. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology. If the drafting team believes communication of additional information regarding ratings needs to be made clearer, the proper place to make the refinement would be in FAC-008-1 and FAC-009-1 not in PRC-023.<br>5. We disagree with the drafting team's assertion in response to the previous set of comments that Requirement 5 is an equally effective way to request data as a Section 1600 data request. First, Section 1600 was specifically written to collect data and that is its main intent. Ending a Section 1600 data request is relatively easy as NERC and the Regions could simply stop collecting the data without any compliance impact on the registered entities. Given the relative value of this data collection on a long term basis, it is highly likely that NERC and the Regional Entities will decide at some point that this data is no longer needed. Secondly, a requirement creates a continuing data request that is subject to sanctions even if the Regional Entities agree that data is no longer needed. Further, changing standards is no easy task given the amount of changes in the queue. The Standards Committee has recently implemented a prioritization tool and plan to limit work on standards to the top 12 or so priorities. There is a good chance seeking a change to eliminate a data request would not be considered a high priority and would result in a significant delay in terminating the data request. Thirdly, this is an administrative/paper compliance type of requirement that provides no direct reliability value. It is exactly the type of requirement that was discussed during the recent FERC Technical Conference on February 8 and that everyone seemed to agree needs to be prioritized out.<br>6. Attachment B describes the sub-100 kV facilities that the Planning Coordinator |

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| | | | | must consider in its assessment as those included in the Regional Entities critical facilities list. We know of no Regional Entity with such a list and there is no requirement for them to develop such a list. This could create the potential for a Planning Coordinator to be in violation because the Regional Entity has not completed its critical facilities list. This is clearly a conflict of interest sine the Regional Entity also monitors compliance and enforces the standards. |

**Response**: Thank you for your comments.

1. The drafting team acknowledges that reliability-based needs for flowgates include concerns other than preventing instability, uncontrolled separation, or cascading. As noted in the NERC Glossary, "Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits." Thus a Flowgate based on Facility Ratings that is not required to prevent instability, uncontrolled separation, or cascading, but may be based on another reliability need. This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. While the IDC may be used to manage congestion in an equitable manner, the drafting team maintains that when the need to manage congestion is based on Facility Ratings or voltage or stability limits, the underlying issue being addressed is system reliability. To the extent that Flowgates are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates.

2. The drafting team believes the test in Attachment B achieves the directive in Order 733 (we believe this is the Order to which the commenter refers) and that deviations from the TPL standards are necessary and appropriate to address concerns stated by FERC, and that such deviations are not precluded by the Order. Specifically, the test identified in criterion B4 is consistent with, and developed specifically to address, the reliability concern driving the need for this standard. System disturbances in which relay loadability was a contributing factor, such as occurred on August 14, 2003, involve multiple contingencies without sufficient time for operator action. The drafting team notes that if manual adjustments were allowed between contingencies in criterion B4, this criterion would not identify any circuits subject to this standard except in cases where TPL-003 is violated. The test appropriately identifies circuits that may be loaded to levels that challenge relay settings when multiple contingencies occur. When such circuits are identified the Facility owner is required to meet relay loadability requirements to prevent the circuit from tripping unnecessarily before an operator has time to take corrective action. The drafting team respectfully points out that the Facility owner is not required to take any action to prevent overloads from occurring under such circumstances; the Facility owner is required only to provide relay loadability per the requirements in PRC-023 to mitigate the potential for such N-2 contingencies from leading to instability, uncontrolled separation, or cascading outages.

3. Requirement R4 has been included to address the FERC concerns stated in Order 733 and to comply with the associated directive. Providing this information to the specified entities addresses the potential for confusion as to the amount of time available to take corrective action.

4. While communicating a Facility Rating would include the time duration associated with the rating, requirements for transmitting the rating do not include any information as to whether the rating is based on a relay setting. The consequences of exceeding a Facility Rating typically follow an inverse-time characteristic; however, when a relay loadability limit is exceeded the circuit may trip in time on the order of

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| 1 second or less, making it important that this information be communicated. Requirements in FAC-008-1 and FAC-009-1 do not require communication of the information addressed in Requirements R3 and R4 of PRC_023-2. The drafting team further notes that Requirement R3 is unchanged from the approved PRC-023-1 Requirement R2 (with the exception of minor formatting) and that inclusion of the new Requirement R4 was directed in Order 733 to addresses stated concerns.<br>5. The drafting team disagrees with the commenter and reasserts that Requirement R5 is an equally effective way to request this data.<br>6. The proposed standard requires Planning Coordinators to apply the criteria in Attachment B to all facilities operated below 100 kV that are on a critical facilities list. The drafting team believes the Planning Coordinator would not be in violation of the standard circuits have been identified by the Regional Entity and the Planning Coordinator failed to apply the criteria. However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES". | | | | |
| Rebecca Berdahl | Bonneville Power Administration | 3 | Negative | 1. BPA believes that there is a major discontinuity in the logical flow of the standard. As described in Section 4.2, the standard applies to certain transmission lines and transformers. In Requirement R1, there are thirteen criteria to select from "for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions". Of these thirteen criteria, only two apply to transformers--number ten and eleven. The way that these two are buried in between the other criteria that apply to line terminals and the way that they are written creates a question as to whether they apply to all transformers or only to transformers that are part of a transformer-terminated line. Additionally, since they are part of the group of thirteen criteria, of which only one must be selected, it appears that criteria ten and eleven can be ignored if another criterion is selected for a transformer-terminated line. BPA forsees this issue causing enough confusion among auditors and transmission owners that we cannot vote in favor of the standard until it is remedied. It would clear up the confusion if Criterion 10 was separated into two parts: one part that deals only with transmission line relays for transformer-terminated lines, and a second part that deals with load-responsive transformer relays. The second part--that deals with load-responsive transformer relays--should be moved along with Criterion 11 into a new requirement. This way, all of the criteria in Requirement 1 will apply only to line relays, with only one of the criteria needed to ensure that the line relays will not limit transmission system loadability. The new requirement (suggest using R2 and bumping the other requirements up a number) would deal specifically with load responsive transformer relays. Because this requirement would not be |

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| | | | | intermingled among the 13 optional criteria of Requirement 1, it would be clear that all load responsive transformer relays--not just those for transformer-terminated lines--were required to comply.<br>2. The drafting team has cleared up a major issue with Criterion 10.1 of Requirement 1 by clarifying that load responsive transformer relays must not expose a transformer to fault levels and durations that exceed the transformers mechanical withstand capability. This makes the requirement achievable, while the earlier version, which required that the relays not expose a transformer to fault levels and durations that exceeded its capability, was not. However, the mechanical withstand capability is not a well defined value, and the drafting team's use of a footnote to clarify this requirement is not sufficient. BPA agrees with the use of IEEE C57.109-1993 as the best way to define mechanical withstand capability, but if this is to be used as the measure of this requirement, it should be written into the requirement and not merely mentioned as a footnote. In addition, Clause 4.4, Figure 4 of IEEE C57.109-1993, as mentioned in the footnote, applies only to Category IV transformers. A close look at the standard reveals that the mechanical withstand capability curves for the other categories are not the same, and the requirements for these other categories must be identified as well. |

**Response**: Thank you for your comments,

1. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that the structure of Requirement R1 is unchanged from the approved PRC-023-1 and is consistent with the “Zone 3” and “Beyond Zone 3” reviews completed by industry following the August 14, 2003 Northeast Blackout. The drafting team provided additional clarity specific to criterion 10 by splitting the fault protection aspect directed in the order (now part 10.1) from the relay loadability aspects. The drafting team believes that combining portions of criteria 10 and 11 at this time would add confusion by intermingling fault protective relays and overload relays. However, the drafting team will include your recommendations in the issues database for future consideration in the next general revision of the standard.

2. The drafting team believes that because the reference does not establish a requirement, rather it defines the phrase mechanical withstand capability, it is most appropriately included as a footnote rather than within Requirement R1, criterion 10. The drafting team also believes that a general citing of IEEE C57.109 within the requirements would be problematic in that we are only referencing a portion of the standard. The drafting team notes that the mechanical withstand is well-defined within the standard and that a specific reference to Clause 4.4, Figure from IEEE C57.109-1993 referenced in PRC-023-2 is sufficient. Category IV transformers are defined as transformers over 10,000 kVA (10 MVA) single-phase or 30,000 kVA (30 MVA) three-phase. Since this standard applies to BES facilities, the drafting team believes that the vast majority (if not all) of the applicable transformers will be Category IV transformers; if any Category III transformers fall within the applicability of this standard, the associated mechanical characteristic is virtually identical.

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| Gregg R Griffin | City of Green Cove Springs | 3 | Negative | From the last posting to this posting, for COM-002-3 R2, the phrase "the accuracy of the message has been confirmed" was added to the second step of three part communication. "Accuracy" is not the correct term here. "Understanding" is a better term. It would seem that "accuracy" is a term to be used in R3, the third part of the 3-part communication so that the issuer of the directive ensures the accuracy of the recipients understanding. FMPA suggests changing COM-002-3 R2 to read: Each Balancing Authority, Transmission Operator, Generator Operator, Transmission Service Provider, Load-Serving Entity, Distribution Provider, and Purchasing-Selling Entity that is the recipient of a Reliability Directive issued per Requirement R1, shall repeat, restate, rephrase or recapitulate the Reliability Directive with enough details to clearly communicate the recipient's understanding of the Reliability Directive.. The term "accuracy" can be interpreted as requiring the recipient to second-guess the Reliability Directive of the RC to enure the accuracy of the RC's directive in the first place. Under tight time constraints of Emergencies, this is not practical. We are sure that was not the intent of the drafting team. For IRO-001-2, FMPA does not see a need for R1. Doesn't the ERO already have that authority to establish RC's through the registration process, and to certify system operators through the PER standards? IRO-014-2 R5, "impacted" was replaced with "other". Wouldn't it be better to at least limit the notification to within the same interconnection? Or is R5 truly to identify all NERC registered RC's? More minor comments / suggestions for improvement: IRO-002 R2 can be improved by replacing "prevent identified events" with "prevent anticipated events". "Anticipated" aligns better with contingency analysis than "identified" IRO-005-4 R1 and R2 can be improved by replacing "expected" with "anticipated". Contingencies are not necessarily "expected"; however, we do "anticipate" them. |
| **Response**: Thank you for your comments. It appears that your comments pertain to Project 2006-06 – Reliability Coordination. The formal comment period for Project 2006-06 is open through March 7, 2011. Please submit your comments through the NERC website. | | | | |
| Michelle A Corley | Cleco Corporation | 3 | Negative | Section 4.2 establishes the conditions to ultimately include the entire electric power infrastructure under the umbrella of protecting the "bulk electric system" which was originally defined as 200kV and above. Cleco is concerned this ever expanding regulatory umbrella is not justified. |
| **Response**: Thank you for your comment.<br><br>The drafting team believes that Section 4.2 will identify only those circuits that if they trip due to relay loadability, may contribute to undesirable system performance similar to what occurred during the August 14, 2003 blackout. The criteria developed in Attachment B were developed to | | | | |

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| achieve this purpose.<br><br>To the extent the commenter is concerned with the reference to facilities operated below 100 kV, the drafting team points out that consistent with the FERC position in Order 733-A we expect that references to circuits operated below 100 kV will have narrow applicability. The drafting team also notes that to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this the reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES." | | | | |
| Henry Ernst-Jr | Duke Energy Carolina | 3 | Affirmative | Duke agrees with the substance of the changes to PRC-023-2, but believe that compliance questions will arise when entities have to sort out the relationship between Section 4.2, Requirement R6 and Attachment B Criteria B5 and B6. Clarifying changes should be made. For example, add the phrase "in accordance with R6" to 4.2.1.2 and 4.2.1.5, then delete 4.2.2, 4.2.2.1 and 4.2.2.2 entirely, and finally, change B5 to the way it was in the last draft, and delete B6. |
| **Response**: Thank you for your comments.<br><br>The drafting team agrees that the phrase "in accordance with R6" should have been included in Applicability Sections 4.2.1.2 and 4.2.1.5 the same as Sections 4.2.1.3 and 4.2.1.6 and has made this modification. The drafting believes that Section 4.2.2 should remain as this section differentiates that the set of circuits to which the Planning Coordinator must apply the criteria in Attachment B is a larger set than the set of circuits for which Facility owners must comply with Requirements R1 through R5 of PRC-023-2.<br><br>The drafting team modified criterion B5 to include consultation with the Facility owner to allow the Facility owner an opportunity to provide insight to the Planning Coordinator performing the analysis. By involving the Facility owner during the Planning Coordinator assessment, the likelihood that the Facility owner will need to utilize the appeals process in Section 1700 of the NERC Rule of Procedure is reduced.<br><br>The drafting team expects that the added criterion B6 will have limited applicability, but it does address a concern raised by commenters during the previous posting. Given that both parties must mutually agree, the drafting team believes there is no potential for undue compliance burden as a result of retaining this criterion. | | | | |
| Kevin Querry | FirstEnergy Solutions | 3 | Affirmative | We applaud the drafting team for their diligent and expeditious work on responding to the FERC directives of Order 733. We support the standard but ask that the team clarify the effective dates. Compliance Application Notice CAN-0013 which was recently posted for industry comment correctly adds clarification to the actual effective date for (1) Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System; (2) Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System; and (3) Switch-on-to-fault schemes on all applicable facilities. Since this CAN specifies the date of October 1, 2013 in the U.S., we ask that the following sections of PRC-023-2 be revised to include this date: "5.1.1.1.3 For switch-on-to- |

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| | | | | fault schemes as described in PRC-023-2 - Attachment A, Section 1.3, the later of the first day of the first calendar quarter after applicable regulatory approval of PRC-023-2 or the first day of the first calendar quarter 39 months following applicable regulatory (October 1, 2013 in the U.S.) approval of PRC-023-1; or in those jurisdictions where no regulatory approval is required, the later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011." and "5.1.2.1 The later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator (October 1, 2013 in the U.S.) of a circuit's inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies." |
| **Response**: Thank you for your comments.<br><br>The drafting team acknowledges the complexity involved in the effective dates for this standard. The drafting team has reformatted the Effective Dates section of the standard into a tabular format consistent with CAN-0013 and has inserted the US effective date (October 1, 2013) where appropriate. | | | | |
| Charles Locke | Kansas City Power & Light Co. | 3 | Negative | 1. The criteria with Attachment B is not consistent with the TPL planning standards and is likely to identify transmission facilities that do not pose a reliability threat to the operation of the interconnection. The criteria in Attachment B should focus on identifying transmission facilities that play a reliability role in maintaining equipment loadings within SOL and IROL facility ratings and not include other considerations such as flowgates which are a mechanism for energy market management.<br>2. In addition, the implementation time frames specified are not clear whether the implementation time frame of 24 months is an extension from the 18 month time frame for the RC to identify circuits using the criteria in Attachment B or if the 24 months is concurrent with the 18 months. Also, it is uncertain whether the 24 months will be sufficient without knowing the impact of the RC analysis. |
| **Response**: Thank you for your comments.<br><br>1. The criteria identified in Attachment B are consistent with, and developed specifically to address, the reliability concern driving the need for this standard. The drafting team continues to believe that Flowgates addressing reliability concerns for loading of circuits is an appropriate inclusion in these criteria. As noted in the NERC Glossary, "Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits." This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. To the extent that Flowgates | | | | |

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| are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates.<br><br>2. The drafting team believes the commenter is referring to the time provided to a Facility owner to comply with PRC-023 after the Planning Coordinator identifies a circuit is subject to PRC-023-2 per application of Attachment B. The drafting team notes that in the previous posting of the standard this timeframe was extended from 24 months to 39 months. Specific to the commenter's question, the standard identifies the 39 months are measured from "notification by the Planning Coordinator of a circuit's inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B." The 39 months in neither concurrent with nor an extension of the 18 months provided to the Planning Coordinator. | | | | |
| Gregory David Woessner | Kissimmee Utility Authority | 3 | Negative | The Regional Entity is not the correct entity to make decisions concerning what < 100 kV equipment is critical or not. It is too subject to inconsistent criteria being applied across the continent. It also is not in alignment with the regulatory construct of a stakeholder process described in Section 215 of the Federal Power Act which affords us the opportunity to learn from each other and develop better answers and solutions that appropriately balance costs, benefits and risks. Development of criteria and the application of that criteria ought to be a collaborative process continent-wide such that the criteria are applied consistently across the continent. This can be done separately, or as part of the BES definition effort currently underway. In the interim, many regions have Planning Coordinators that are not self-regulating, e.g., the Planning Coordinator is separate from the asset owners. Most of the Planning Coordinators are stakeholder organization whose "Planning Committees" would make the determination. For entities that do self-regulate, e.g., they are both the asset owner and Planning Coordinator, presumably the Regional Entity could form a stakeholder process with a Planning Committee whose members include appropriate and balanced representation from the stakeholders. These "Planning Committees" could be an alternative source for a stakeholder process to determine criteria for < 100 kV Applicability and apply that criteria while a continent-wide effort is underway to determine that criteria. These "Planning Committees" could remain in place to apply the continent-wide criteria to the regional system. |
| **Response**: Thank you for your comment.<br><br>The drafting team notes that PRC-023 does not grant the Regional Entity any authority, rather it reflects language already contained in the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list entities that do not own or operate "a transmission element below 100 kV associated with <u>a facility that is included on a critical facilities list that is defined by the Regional Entity</u> (emphasis added)." However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES". | | | | |

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| Greg C. Parent | Manitoba Hydro | 3 | Negative | Please see comments previously submitted by Manitoba Hydro regarding the effective date and the items included in Section 1.6 of Attachment A. |
| **Response**: Thank you for your comments.<br>1. The drafting team has considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1. Extending the timeframe included consideration of the number of circuits that may be identified by the Planning Coordinator.<br>2. Items included in Section 1.6 of Attachment A are included to address the concerns noted by FERC in Order 733. Settings for the protection schemes of concern are often very sensitive – well below load current – and dependent on the integrity of the communication channel to make a trip/no trip decision where other telecommunication system technologies require the operation of other protection system elements (usually distance elements) which are already subject to the requirements of this standard. Therefore, they will trip immediately due to load current upon the loss of communications, and are dependent on the fault detectors to inhibit trip which must therefore be secure regardless of how infrequently loss of communications may occur. | | | | |
| Thomas C. Mielnik | MidAmerican Energy Co. | 3 | Negative | 1. The Attachment B5 criteria determining critical facilities appears to be wide open and eliminates the facility planner/owner's authority to determine what are and are not "critical" facilities on its own system based upon wording in Attachment B. To give one entity, the Planning Coordinator, the power to assign the designation of "critical" potentially over a facility planners/owners objection based upon any study or study criteria the Planning Coordinator decides is valid is inappropriate and also potentially result in reduced reliability. There may be issues that the Transmission Planner may know about or know more about that the Planning Coordinator does not. Criteria B5 should be deleted. If B5 is not deleted, a minimum, the B5 wording "in consultation with" should be replaced with "upon mutual agreement with". The facility planner/owner who best understands its facilities should have some final say in conjunction with its Planning Coordinator in determining what is and is not critical to its system and the region.<br>2. The drafting team change in Attachment B1 of adding the word "permanent" in front of "flowgate" did not correct the fundamental issue that a "flowgate" is not by definition a reliability issue and has no more measurable risk than the loss of any other BES transmission element. An example is the loss of a 161 kV flowgate, might have less reliability impact than the loss of a 345 or 500 kV line that is not designated as a flowgate. Therefore the criteria to define a "critical" facility through a flowgate designation is fundamentally in error. A better definition of "critical" is if the loss of a transmission element results in instability, |

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| | | | | uncontrolled separation, and cascading as defined in the Federal Power Act. |
| **Response**: Thank you for your comments.<br>1. The authority for identifying circuits below 200 kV for which Facility owners must comply with PRC-023-2 is assigned to the Planning Coordinators in PRC-023-1. The drafting team believes that criterion B5 in Attachment B of PRC-023-2 is not wide-open because it requires that the determination must (i) be based on technical studies or assessments and (ii) must be made in consultation with the Facility owner. While the drafting team understands the need for Facility owner input, we also believe it is inappropriate to give the Facility Owner de facto veto power by using the phrase “upon mutual agreement with.” We believe the Planning Coordinator will give due consideration to the Facility owner’s input, and in cases where the Facility owner disagrees with the determination of the Planning Coordinator, they are free to use the appeals process in Section 1700 of the NERC Rules of Procedure that was developed to address this concern.<br>2. As noted in the NERC Glossary, “Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits.” This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. To the extent that Flowgates are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates. | | | | |
| John S Bos | Muscatine Power & Water | 3 | Affirmative | How does the STD feel about the possibility of conflicts between the Planning Coordinator and the Facility Owner pertaining to B5? How would these unforseen conflicts be resolved? |
| **Response**: Thank you for your comment.<br>As directed in ¶97 of Order 733, NERC has developed an appeals process so that Facility owners may challenge the determination of the Planning Coordinators. The appeals process will be contained in Section 1700 of the NERC Rules of Procedure. | | | | |
| Michael Schiavone | Niagara Mohawk (National Grid Company) | 3 | Affirmative | 1. List of Critical Facilities: Since a critical facilities list would be prepared for other reasons (e.g. CIP-002), National Grid is assuming that the list of critical facilities will be reviewed for applicability to PRC-023 and that a subset of the list may need to be defined for this application.<br>2. There appears to be inconsistency in the wording pertaining to the sentence - "critical facilities list defined by the Regional Entity and selected by the Planning Coordinator". In 4.2.1.3 the aforementioned sentence is produced in its entirety. However, in attachment B, under Circuits to Evaluate, bullet point 2, the sentence is missing "...and selected by the Planning Coordinator". This piece is also missing in 4.2.2.2.<br>3. Attachment B, B4 a.: National Grid requests the drafting team to explain the rationale behind deleting "Category C3" from B4. National Grid believes that by |

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| | | | | providing reference to Category C3, the standard focuses on the scope and provides for consistency in the engineering judgment. However, by deleting Category C3, the scope becomes undefined as to the level of combinations that need to be assessed and will concern the engineer that his engineering judgment can be called into question.<br>4. Summary consideration on pg. 1 regarding supervisory elements associated with current based, communication assisted schemes having to meet PRC-023-2 and inclusion of such elements in Attachment A, 1.6: This is taken to mean line differential schemes. If the supervisory elements for a line diff must be set high enough to comply with PRC-023-2 that will make the entire scheme extremely insensitive to faults. For example R1.1 would require the supervising elements be set > 1.5 x the 4 hr. loading meaning the scheme will be unable to detect an internal fault unless it exceeds 1.5 x the 4 hr. loading. That negates one of the chief advantages of using a line differential scheme in the first place, specifically it's sensitivity. If the communications for a relay scheme is lost the scheme is essentially "broken" and to require it to still function correctly per PRC-023-2 even when broken is unreasonable. There is no requirement that distance schemes conform to PRC-023-2 if they are broken, for example if they lose their restraint potential they will trip on load too.<br>5. Switch on to fault scheme included in Attachment A, 1.3 - An exception needs to be added for those schemes that are smart enough to detect a live line condition and which are disabled when closing or reclosing into an already energized line. Such schemes will not respond to current flow into and through a live line. Requiring that such a SOTF scheme that can recognize a live line be set to carry through current regardless, negates the advantage of the scheme in the first place, specifically its sensitivity.<br>6. Regarding R1, Criterion 10 - What if the transformer at the end of the line has its own overcurrent protection that either trips a local high side breaker or circuit switcher or TT's the other end of the source line and this transformer overcurrent protection is set below the mechanical damage curve. Must the line protection back at the source to the line still be set below the transformer's mechanical damage curve? If your answer is yes, what if the line protection is step distance with a flat timer, like a zone 2 timer. Coordinating a zone 2 looking into the transformer and having a flat zone 2 timer against and inverse transformer mechanical damage curve is awkward at best and maybe not even feasible.<br>7. Regarding R1, Criterion 5 - "Weak source system" is a relative term. Is the reader free to define "weak" as the reader chooses? If not then it needs to be |

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<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td></td><td>defined in the standard.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.<br>1. Yes, additional screening will be applied. The Planning Coordinator is required to apply the criteria in Attachment B to these facilities to identify which circuits on the list are relevant to the reliability objective of PRC-023-2.<br>2. These differences are intentional. Where the phrase is not included it is referring to the circuits that must be evaluated by the Planning Coordinator. The Planning Coordinator must apply the criteria in Attachment B to all facilities operated below 100 kV that are on a critical facilities list. However, the Facility owners are required to comply with PRC-023-2 only for those circuits selected by the Planning Coordinator in accordance with Requirement R6.<br>3. The reference to category C3 contingencies resulted in confusion with some entities because the test required in criterion B4 is not the same as category C3 since criterion B4 does not include manual system adjustments between contingencies.<br>4. Items included in Section 1.6 of Attachment A are included to address the concerns noted by FERC in Order 733. Settings for the protection schemes of concern are often very sensitive – well below load current – and dependent on the integrity of the communication channel to make a trip/no trip decision where other telecommunication system technologies require the operation of other protection system elements (usually distance elements) which are already subject to the requirements of this standard. Therefore, they will trip immediately due to load current upon the loss of communications, and are dependent on the fault detectors to inhibit trip which must therefore be secure regardless of how infrequently loss of communications may occur.<br>5. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that Attachment A, Section 1.3 is unchanged from the approved PRC-023-1. However, the drafting team will include your recommendations in the issues database for future consideration in the next general revision of the standard.<br>6. No, in the previous posting the drafting team separated the relay loadability aspect and the transformer fault protection aspect of criterion 10. The transformer fault protection relays and transmission line relays both must meet the relay loadability requirements listed in the two bullets in criterion 10. Only the transformer fault protection relays, if used, must be coordinated with the transformer mechanical withstand capability.<br>7. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that Requirement R1, criterion 5 is unchanged from the approved PRC-023-1. Entities may apply criterion 5 to any line, although when the source becomes sufficiently strong this criterion will become more restrictive than others.</td></tr>
<tr><td>David Schiada</td><td>Southern California Edison Co.</td><td>3</td><td>Negative</td><td>We do not feel that the concerns raised in comments on the last round of balloting have been adequately addressed. Among the concerns still remaining are the use of "critical facilities" in several of the requirements and the respective roles that Regional Entities and Planning Coordinators will play in identifying critical facilities.</td></tr>
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| Voter | Entity | Segment | Vote | Comment |
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| **Response**: Thank you for your comments.<br><br>The Regional Entity may develop a list of critical facilities by means outside this standard. The reference to a list of critical facilities in PRC-023-2 is in the same context as the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list an entity that does not own or operate “a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity (emphasis added).” To provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has replaced the reference to a “list of critical facilities” with a reference to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are “part of the BES.”<br><br>The role of the Planning Coordinator is defined in Requirement R6. The Planning Coordinator will be required to apply the criteria in Attachment B in accordance with Requirement R6 of PRC-023-2 to identify any circuits on the list for which the Facility owner must comply with PRC-023-2. | | | | |
| Ian S Grant | Tennessee Valley Authority | 3 | Affirmative | For Attachment B part B1: “Permanent flowgate” is too ambiguous. Most entities in the eastern interconnect use flowgates in many different processes such as EMS systems and state estimator, transfer capability calculations, congestion management processes, and market calculations. All of these processes have flowgates that could be considered “permanent”. If this standard is pointing to the IDC Book of Flowgate (BOF) Permanent flowgates, then this should be so stated. However, since the IDC BOFs is not the most up to date list of flowgates, we suggest that a better line criticality identification to reliability is if a TLR has been called on the flowgate in the last two year. We recommend that instead of “permanent flowgate”, the B1 portion of Attachment B1 should say “ in the IDC Book of Flowgates and a TLR 3 or greater has been called on the flowgate in the last two years”. |
| **Response**: Thank you for your comments.<br><br>The drafting team appreciates the suggestion to further refine the Flowgates of interest in the context of criterion B1. However, the drafting team believes that the Flowgates of interest must be determined based on the reliability basis for adding the Flowgate rather than historical transfers. Even if a TLR has not been called on a Flowgate for an extended period of time, during a system disturbance an overload on a monitored Facility comprising the Flowgate could lead to cascading outages if relay loadability requirements are not met. The drafting team believes it is best to continue to refer to circuits that are monitored Facilities of Flowgates that are included to address reliability concerns for loading of those circuits. | | | | |
| David Frank Ronk | Consumers Energy | 4 | Negative | As a Generator Owner dependent on a Transmission Provider, access to information about the transmission relays seems to be required for us to comply with this proposed Standard. It does not seem that the Transmission Provider is required to furnish us this information. Requiring information transfer without writing it into the Standard places us in needless jeopardy. |

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td colspan="5">Response: Thank you for your comment.<br><br>As described in the Applicability section of the standard, Generator Owners are only subject to compliance with Requirements R1 through R5 to the extent they own load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1. If a Generator Owner owns such relays they should have information available necessary to set the relays and confirm relay loadability requirements are met.</td></tr>
<tr><td>Frank Gaffney</td><td>Florida Municipal Power Agency</td><td>4</td><td>Negative</td><td>The Regional Entity is not the correct entity to make decisions concerning what < 100 kV equipment is critical or not. It is too subject to inconsistent criteria being applied across the continent. It also is not in alignment with the regulatory construct of a stakeholder process described in Section 215 of the Federal Power Act which affords us the opportunity to learn from each other and develop better answers and solutions that appropriately balance costs, benefits and risks. Development of criteria and the application of that criteria ought to be a collaborative process continent-wide such that the criteria are applied consistently across the continent. This can be done separately, or as part of the BES definition effort currently underway. In the interim, many regions have Planning Coordinators that are not self-regulating, e.g., the Planning Coordinator is separate from the asset owners. Most of the Planning Coordinators are stakeholder organization whose "Planning Committees" would make the determination. For entities that do self-regulate, e.g., they are both the asset owner and Planning Coordinator, presumably the Regional Entity could form a stakeholder process with a Planning Committee whose members include appropriate and balanced representation from the stakeholders. These "Planning Committees" could be an alternative source for a stakeholder process to determine criteria for < 100 kV Applicability and apply that criteria while a continent-wide effort is underway to determine that criteria. These "Planning Committees" could remain in place to apply the continent-wide criteria to the regional system.</td></tr>
<tr><td colspan="5">Response: Thank you for your comment.<br><br>The drafting team notes that PRC-023 does not grant the Regional Entity any authority, rather it reflects language already contained in the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list entities that do not own or operate “a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity (emphasis added).” However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are “part of the BES.”</td></tr>
<tr><td>Thomas W. Richards</td><td>Fort Pierce Utilities</td><td>4</td><td>Negative</td><td>The Regional Entity is not the correct entity to make decisions concerning what < 100 kV equipment is critical or not. It is too subject to inconsistent criteria being</td></tr>
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| **Response**: Thank you for your comment.<br>The drafting team notes that PRC-023 does not grant the Regional Entity any authority, rather it reflects language already contained in the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list entities that do not own or operate "a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity (emphasis added)." However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES." | | | | |
| Bob C. Thomas | Illinois Municipal Electric Agency | 4 | Negative | Illinois Municipal Electric Agency (IMEA) appreciates the SDT's efforts to include provisions which distinguish applicability to < 100 kV lines and transformers on a critical facilities list. IMEA supports comments to this effect as submitted by Florida Municipal Power Agancy. |
| **Response**: Thank you for your comment.<br>The drafting team notes that PRC-023 does not grant the Regional Entity any authority, rather it reflects language already contained in the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list entities that do not own or operate "a transmission element below 100 kV associated with a facility that is included on a critical facilities list that is defined by the Regional Entity (emphasis added)." However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under | | | | |

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| development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES." | | | | |
| Douglas Hohlbaugh | Ohio Edison Company | 4 | Affirmative | We applaud the drafting team for their diligent and expeditious work on responding to the FERC directives of Order 733. We support the standard but ask that the team clarify the effective dates. Compliance Application Notice CAN-0013 which was recently posted for industry comment correctly adds clarification to the actual effective date for (1) Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System; (2) Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System; and (3) Switch-on-to-fault schemes on all applicable facilities. Since this CAN specifies the date of October 1, 2013 in the U.S., we ask that the following sections of PRC-023-2 be revised to include this date: "5.1.1.1.3 For switch-on-to-fault schemes as described in PRC-023-2 - Attachment A, Section 1.3, the later of the first day of the first calendar quarter after applicable regulatory approval of PRC-023-2 or the first day of the first calendar quarter 39 months following applicable regulatory (October 1, 2013 in the U.S.) approval of PRC-023-1; or in those jurisdictions where no regulatory approval is required, the later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011." and "5.1.2.1 The later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator (October 1, 2013 in the U.S.) of a circuit's inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies." |
| **Response**: Thank you for your comments.<br><br>The drafting team acknowledges the complexity involved in the effective dates for this standard. The drafting team has reformatted the Effective Dates section of the standard into a tabular format consistent with CAN-0013 and has inserted the US effective date (October 1, 2013) where appropriate. | | | | |
| Brock Ondayko | AEP Service Corp. | 5 | Affirmative | The wording of Attachment A, section 1.6 should be made consistent to avoid any confusion. AEP suggests that it be reworded to read: "Supervisory elements used as fault detectors associated with pilot wire or current differential protection systems where the system is capable of tripping for loss of communications". |

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| **Response**: Thank you for your comments.<br><br>The drafting team apologizes for confusion regarding Attachment A, Section 1.6 during the previous posting. The drafting team had intended to provide additional clarification. The drafting team has inserted parenthetical statements to clarify that the phrase "phase overcurrent supervisory elements" refers to phase fault detectors and "current-based communication-assisted schemes" refers to pilot wire, phase comparison, and line current differential schemes. We believe this modification is in-line with your recommended modification. | | | | |
| Francis J. Halpin | Bonneville Power Administration | 5 | Negative | 1. BPA believes that there is a major discontinuity in the logical flow of the standard. As described in Section 4.2, the standard applies to certain transmission lines and transformers. In Requirement R1, there are thirteen criteria to select from "for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions". Of these thirteen criteria, only two apply to transformers--number ten and eleven. The way that these two are buried in between the other criteria that apply to line terminals and the way that they are written creates a question as to whether they apply to all transformers or only to transformers that are part of a transformer-terminated line. Additionally, since they are part of the group of thirteen criteria, of which only one must be selected, it appears that criteria ten and eleven can be ignored if another criterion is selected for a transformer-terminated line. BPA forsees this issue causing enough confusion among auditors and transmission owners that we cannot vote in favor of the standard until it is remedied. It would clear up the confusion if Criterion 10 was separated into two parts: one part that deals only with transmission line relays for transformer-terminated lines, and a second part that deals with load-responsive transformer relays. The second part--that deals with load-responsive transformer relays--should be moved along with Criterion 11 into a new requirement. This way, all of the criteria in Requirement 1 will apply only to line relays, with only one of the criteria needed to ensure that the line relays will not limit transmission system loadability. The new requirement (suggest using R2 and bumping the other requirements up a number) would deal specifically with load responsive transformer relays. Because this requirement would not be intermingled among the 13 optional criteria of Requirement 1, it would be clear that all load responsive transformer relays--not just those for transformer-terminated lines--were required to comply.<br>2. The drafting team has cleared up a major issue with Criterion 10.1 of Requirement 1 by clarifying that load responsive transformer relays must not expose a transformer to fault levels and durations that exceed the transformers mechanical withstand capability. This makes the requirement achievable, while |

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| | | | | the earlier version, which required that the relays not expose a transformer to fault levels and durations that exceeded its capability, was not. However, the mechanical withstand capability is not a well defined value, and the drafting team's use of a footnote to clarify this requirement is not sufficient. BPA agrees with the use of IEEE C57.109-1993 as the best way to define mechanical withstand capability, but if this is to be used as the measure of this requirement, it should be written into the requirement and not merely mentioned as a footnote. In addition, Clause 4.4, Figure 4 of IEEE C57.109-1993, as mentioned in the footnote, applies only to Category IV transformers. A close look at the standard reveals that the mechanical withstand capability curves for the other categories are not the same, and the requirements for these other categories must be identified as well. |
| **Response**: Thank you for your comments.<br>1. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that the structure of Requirement R1 is unchanged from the approved PRC-023-1 and is consistent with the "Zone 3" and "Beyond Zone 3" reviews completed by industry following the August 14, 2003 Northeast Blackout. The drafting team provided additional clarity specific to criterion 10 by splitting the fault protection aspect directed in the order (now part 10.1) from the relay loadability aspects. The drafting team believes that combining portions of criteria 10 and 11 at this time would add confusion by intermingling fault protective relays and overload relays. However, the drafting team will include your recommendations in the issues database for future consideration in the next general revision of the standard.<br>2. The drafting team believes that because the reference does not establish a requirement, rather it defines the phrase mechanical withstand capability, it is most appropriately included as a footnote rather than within Requirement R1, criterion 10. The drafting team also believes that a general citing of IEEE C57.109 within the requirements would be problematic in that we are only referencing a portion of the standard. The drafting team notes that the mechanical withstand is well-defined within the standard and that a specific reference to Clause 4.4, Figure from IEEE C57.109-1993 referenced in PRC-023-2 is sufficient. Category IV transformers are defined as transformers over 10,000 kVA (10 MVA) single-phase or 30,000 kVA (30 MVA) three-phase. Since this standard applies to BES facilities, the drafting team believes that the vast majority (if not all) of the applicable transformers will be Category IV transformers; if any Category III transformers fall within the applicability of this standard, the associated mechanical characteristic is virtually identical. | | | | |
| James B Lewis | Consumers Energy | 5 | Negative | As a Generator Owner dependant on a Transmission Provider, access to information about the transmission relays seems to be required for us to comply with this proposed Standard. It does not seem that the Transmission Provider is required to furnish us this information. Requiring information transfer without writing it into the Standard places us in needless jeopardy. |

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| **Response**: Thank you for your comment.<br><br>As described in the Applicability section of the standard, Generator Owners are only subject to compliance with Requirements R1 through R5 to the extent they own load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1. If a Generator Owner owns such relays they should have information available necessary to set the relays and confirm relay loadability requirements are met. | | | | |
| Rex A Roehl | Indeck Energy Services, Inc. | 5 | Negative | This standard should not apply to generators. To the extent that a particular generator qualifies for some of the requirements of this standard, they should be specially applied, as has been done by WECC for generators with long transmission lines. There are 820 GO and 780 GOP registered entities. It is unlikely that many of them qualify. It would take an expensive consultant a substantial amount of time to understand the standard such that a determination could be made for a GO/GOP if it qualified. This is an unnecessary burden. The applicability section should be modified as such. |
| **Response**: Thank you for your comments.<br><br>As described in the Applicability section of the standard, Generator Owners are only subject to compliance with Requirements R1 through R5 to the extent they own load-responsive phase protection systems as described in PRC-023-2 - Attachment A, applied to circuits defined in 4.2.1. In order to achieve the reliability objective of this standard, it is necessary for all entities that own such relays to meet the relay loadability requirements. | | | | |
| Scott Heidtbrink | Kansas City Power & Light Co. | 5 | Negative | 1. The criteria with Attachment B is not consistent with the TPL planning standards and is likely to identify transmission facilities that do not pose a reliability threat to the operation of the interconnection. The criteria in Attachment B should focus on identifying transmission facilities that play a reliability role in maintaining equipment loadings within SOL and IROL facility ratings and not include other considerations such as flowgates which are a mechanism for energy market management.<br>2. In addition, the implementation time frames specified are not clear whether the implementation time frame of 24 months is an extension from the 18 month time frame for the RC to identify circuits using the criteria in Attachment B or if the 24 months is concurrent with the 18 months. Also, it is uncertain whether the 24 months will be sufficient without knowing the impact of the RC analysis. |
| **Response**: Thank you for your comments.<br><br>1. The criteria identified in Attachment B are consistent with, and developed specifically to address, the reliability concern driving the need for this standard. The drafting team continues to believe that Flowgates addressing reliability concerns for loading of circuits is an appropriate inclusion in these criteria. As noted in the NERC Glossary, “Total Flowgate Capabilities are determined based on Facility Ratings and voltage | | | | |

<table>
<tr><th>Voter</th><th>Entity</th><th>Segment</th><th>Vote</th><th>Comment</th></tr>
<tr><td colspan="5">and stability limits.” This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. To the extent that Flowgates are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates.<br><br>2. The drafting team believes the commenter is referring to the time provided to a Facility owner to comply with PRC-023 after the Planning Coordinator identifies a circuit is subject to PRC-023-2 per application of Attachment B. The drafting team notes that in the previous posting of the standard this timeframe was extended from 24 months to 39 months. Specific to the commenter’s question, the standard identifies the 39 months are measured from “notification by the Planning Coordinator of a circuit’s inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B.” The 39 months in neither concurrent with nor an extension of the 18 months provided to the Planning Coordinator.</td></tr>
<tr><td>S N Fernando</td><td>Manitoba Hydro</td><td>5</td><td>Negative</td><td>Please see comments previously submitted by Manitoba Hydro regarding the effective date and the items included in Section 1.6 of Attachment A.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.<br><br>1. The drafting team has considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1. Extending the timeframe included consideration of the number of circuits that may be identified by the Planning Coordinator.<br><br>2. Items included in Section 1.6 of Attachment A are included to address the concerns noted by FERC in Order 733. Settings for the protection schemes of concern are often very sensitive – well below load current – and dependent on the integrity of the communication channel to make a trip/no trip decision where other telecommunication system technologies require the operation of other protection system elements (usually distance elements) which are already subject to the requirements of this standard. Therefore, they will trip immediately due to load current upon the loss of communications, and are dependent on the fault detectors to inhibit trip which must therefore be secure regardless of how infrequently loss of communications may occur.</td></tr>
<tr><td>Christopher Schneider</td><td>MidAmerican Energy Co.</td><td>5</td><td>Negative</td><td>1. Comment: The Attachment B5 criteria determining critical facilities appears to be wide open and eliminates the facility owner’s authority to determine what are and are not “critical” facilities on its own system based upon wording in Attachment B. The word “critical” is used throughout other NERC standards and has many potential implications. To give one entity, the Planning Coordinator, the power to assign the designation of “critical” potentially over a facility owners objection based upon any study or study criteria the Planning Coordinator decides is valid is inappropriate. Criteria B5 should be deleted. If B5 is not deleted, a minimum, the B5 wording “in consultation with” should be replaced with “upon mutual agreement with”. The facility owner who best understands its facilities should have some final say in conjunction with its Planning</td></tr>
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| | | | | Coordinator in determining what is and is not critical to its system and the region.<br>2. The drafting team change in Attachment B1 of adding the word “permanent” in front of “flowgate” did not correct the fundamental issue that a “flowgate” is not by definition a reliability issue and has no more measurable risk than the loss of any other BES transmission element. An example is the loss of a 161 kV flowgate, might have less reliability impact than the loss of a 345 or 500 kV line that is not designated as a flowgate. Therefore the criteria to define a “critical” facility through a flowgate designation is fundamentally in error. A better definition of “critical” is if the loss of a transmission element results in instability, uncontrolled separation, and cascading as defined in the Federal Power Act.<br>3. Vote negative on the VSLs Nearly all the VSLs are a binary in nature resulting in a zero defect standard with a “severe” result. This is an incorrect usage of the VSL concept which was to show graduated levels of risk, not deterministic zero defect results. This incorrect enforcement concept actually slows reliability progress by delaying standard implementation and hurts the concept of the new “administrative ticket process”. FERC will be reluctant to allow the administrative ticket process to be used for a “severe” VSL violation even if it can be shown there was little to no BES risk. |

**Response**: Thank you for your Comments.

1. The authority for identifying circuits below 200 kV for which Facility owners must comply with PRC-023-2 is assigned to the Planning Coordinators in PRC-023-1. The drafting team believes that criterion B5 in Attachment B of PRC-023-2 is not wide-open because it requires that the determination must (i) be based on technical studies or assessments and (ii) must be made in consultation with the Facility owner. While the drafting team understands the need for Facility owner input, we also believe it is inappropriate to give the Facility Owner de facto veto power by using the phrase “upon mutual agreement with.” We believe the Planning Coordinator will give due consideration to the Facility owner’s input, and in cases where the Facility owner disagrees with the determination of the Planning Coordinator they are free to use the appeals process in Section 1700 of the NERC Rules of Procedure that was developed to address this concern.

2. As noted in the NERC Glossary, “Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits.” This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. To the extent that Flowgates are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates.

3. Requirements R1 through R5 are similar in structure to Requirements R1 and R2 in the approved PRC-023-1. FERC directed binary VSLs for Requirements R1 and R2 in Order 733 and the drafting team believes binary VSLs for Requirements R1 through R5 in PRC-023-2 are

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| consistent with that Order. | | | | |
| Michelle DAntuono | Occidental Chemical | 5 | Negative | 1. Need justification as to why lines below 100 KV that are included on a critical facilities list defined by the Regional Entity are also processed through the Attachment B criteria list. The previous version did not consider lines below 100KV.<br>2. Attachment B still allows the PC to select facilities below 200KV based on criteria/studies other than specified in the rest of Attachment B, but requires this to be done “in consultation with the Facility owner.” This prompts close scrutiny of the challenge process that is required under the FERC Order. This also causes Regional discrepancies, which NERC is trying to steer away from. There should be “bright line” across all Regions.<br>3. Need justification as to why the VSLs are listed as Severe.<br>4. There is required annual reporting, which begs the question of what is required of a Registered Entity that has nothing to report? |
| **Response**:<br>1. The drafting team modified Attachment B in response to industry comments. Based on comments during the previous posting, the drafting team believes it is appropriate to assess sub-100 kV circuits using the same methodology applied to circuits operated at 100 kV to 200 kV. Requiring applicable entities to comply for all sub-100 kV circuits included on a critical facilities list defined by the Regional Entity results in a higher standard for sub-100 kV circuits, and is inconsistent with the directive in ¶60 of Order No. 733.<br>2. Criteria B1 through B4 in Attachment B provide a consistent methodology for Planning Coordinators to apply across all regions. In recognition that these criteria may not identify every circuit that presents a risk of cascading outages if relay loadability requirements are not met, criteria B5 and B6 have been included. The drafting team believes that criteria B1 through B4 will identify the majority of circuits of concern, and that criteria B5 and B6 will be used only in unique cases that cannot be captured in a bright-line definition.<br>3. Requirements R1 through R5 are similar in structure to Requirements R1 and R2 in the approved PRC-023-1. FERC directed binary VSLs for Requirements R1 and R2 in Order 733 and the drafting team believes binary VSLs for Requirements R1 through R5 in PRC-023-2 are consistent with that Order. In the case of binary VSLs, the VSLs are set to Severe by definition.<br>4. Measures M4 and M5 have been updated to indicate that “The updated list may be a full list, a list of incremental changes to the previous list, or a statement that there are no changes to the previous list”. | | | | |
| Sandra L. Shaffer | PacifiCorp | 5 | Negative | 1. PacifiCorp agrees with what it understands are the general concepts contained in Applicability Section 4.2, Requirements R6 and R7, and Attachment B of the proposed PRC-023-2. Namely, that: 1) the standard applies to all facilities (defined in Attachment A) above 200 kV and some facilities below 200 kV; 2) the Planning Coordinator is responsible for identifying the 100 - 200 KV facilities |

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| | | | | (defined in Attachment A) to which the standard will apply (based on Attachment B); 3) some combination of the Regional Entity and the Planning Coordinator are responsible for identifying below 100 kV facilities (defined in Attachment A) to which the standard will apply (based on Attachment B); and 4) Transmission Owners, Generator Owners, and Distribution Providers that own the facilities that have been deemed applicable are responsible for complying with the requirements of the standard. If PacifiCorp's understanding of these concepts is generally correct, they must be more clearly stated in PRC-023-2.<br>2. As is currently drafted, the language contained in the applicability section, Requirements R6 and R7, and Attachment B are circular, unclear, and redundant. In order for registered entities to understand their obligations, the standards must be absolutely clear on what is required and by whom. PacifiCorp suggests the following: 1) remove R6 because it is redundant with the Applicability Section 4.2 (or vice versa) and clarify the role of the Planning Coordinator and the application of Attachment B criteria; 2) Applicability Section 4.2.3 and the second bullet in Attachment B appear to contradict as Section 4.2.3 defines a role for the Planning Coordinator whereas the second bullet in Attachment B does not - this may be correct for some reason, however, the role of the Planning Coordinator and the Regional Entity in evaluating facilities below 100 kV must be more clearly defined. PacifiCorp does not have any substantive issues with the Attachment B criteria. However, in order to be enforceable, the legal obligations imposed on registered entities under PRC-023-2 must be more clearly stated. |
| **Response**: Thank you for your comment.<br>1. The understanding described in your first comment are correct, although the drafting team notes that Requirement R7 was removed prior to posting the standard for comments and concurrent ballot. In addition to removing Requirement R7, the drafting team made a number of clarifying modifications to the Applicability, Requirement R6, and Attachment B.<br>2. The commenter has made references to Requirement 7 and to an Applicability section that are not part of the standard that was posted for comment and concurrent ballot. We believe that the restructured Applicability section and clarifying modifications to Requirement R6 and Attachment B address the commenter's concerns related to clarity and circularity. | | | | |
| David Thompson | Tennessee Valley Authority | 5 | Affirmative | For Attachment B part B1: "Permanent flowgate" is too ambiguous. Most entities in the eastern interconnect use flowgates in many different processes such as EMS systems and state estimator, transfer capability calculations, congestion management processes, and market calculations. All of these processes have |

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| | | | | flowgates that could be considered “permanent”. If this standard is pointing to the IDC Book of Flowgate (BOF) Permanent flowgates, then this should be so stated. However, since the IDC BOFs is not the most up to date list of flowgates, we suggest that a better line criticality identification to reliability is if a TLR has been called on the flowgate in the last two year. We recommend that instead of “permanent flowgate”, the B1 portion of Attachment B1 should say “ in the IDC Book of Flowgates and a TLR 3 or greater has been called on the flowgate in the last two years”. |
| **Response**: Thank you for your comments.<br><br>The drafting team appreciates the suggestion to further refine the Flowgates of interest in the context of criterion B1. However, the drafting team believes that the Flowgates of interest must be determined based on the reliability basis for adding the Flowgate rather than historical transfers. Even if a TLR has not been called on a Flowgate for an extended period of time, during a system disturbance an overload on a monitored Facility comprising the Flowgate could lead to cascading outages if relay loadability requirements are not met. The drafting team believes it is best to continue to refer to circuits that are monitored Facilities of Flowgates that are included to address reliability concerns for loading of those circuits. | | | | |
| Edward P. Cox | AEP Marketing | 6 | Affirmative | The wording of Attachment A, section 1.6 should be made consistent to avoid any confusion. AEP suggests that it be reworded to read: "Supervisory elements used as fault detectors associated with pilot wire or current differential protection systems where the system is capable of tripping for loss of communications". |
| **Response**: Thank you for your comment.<br><br>The drafting team apologizes for confusion regarding Attachment A, Section 1.6 during the previous posting. The drafting team had intended to provide additional clarification. The drafting team has inserted parenthetical statements to clarify that the phrase “phase overcurrent supervisory elements” refers to phase fault detectors and “current-based communication-assisted schemes” refers to pilot wire, phase comparison, and line current differential schemes. We believe this modification is in-line with your recommended modification. | | | | |
| Jennifer Richardson | Ameren Energy Marketing Co. | 6 | Negative | (1) We do not agree with the implied establishment of ratings outside of the requirements of FAC-008 in Requirement R1, criterion 1, which implies the establishment of a 4 hour rating. Rather than specifically identify the duration, the term ‘highest seasonal long-term emergency’ rating should be used.<br><br>(2) Attachment B Criterion B1 still includes the consideration of flowgates. We believe that this criterion should be removed from Attachment B.<br><br>(3) Attachment B Criterion B4 includes the consideration of double contingency |

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| | | | | events without manual system adjustments between contingencies. While the specific mention of Category C3 contingencies is removed, which would permit limiting consideration of multiple contingency events to Category C1 bus fault, C2 breaker failure, and C5 common structure outages where no operator intervention would be possible, such contingency selection would be up to the Planning Coordinator, not the individual Transmission Owner. As written, the Facility owner would only have input as to the threshold level against which the post-contingency loading would be compared, rather than the selection of the multiple contingencies to be simulated. Any 'N-1-1' contingencies should be considered as congestion issues and should not be considered as part of the criteria in Attachment B for this reliability standard. |

**Response**: Thank you for your comments.

1. The drafting team would understand this concern if the standard required that entities establish 4-hour ratings; however, the drafting team notes that this criterion intentionally refers to "the available defined loading duration nearest 4 hours" to make it clear that an entity is not required to develop a 4-hour rating. An entity may use an existing rating, for any time duration, so long as when multiple ratings are available an entity uses their existing rating that is based on a time duration nearest to 4 hours. This phrase has remained unchanged from the "Zone 3" and "Beyond Zone 3" reviews completed following the August 14, 2003 Northeast Blackout and is part of the approved standard PRC-023-1. The drafting team is not aware of any assertion that this criterion establishes a de facto requirement for entities to develop ratings based on 4-hour duration.

2. As noted in the NERC Glossary, "Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits." This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. To the extent that Flowgates are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates.

3. The test identified in criterion B4 is consistent with, and developed specifically to address, the reliability concern driving the need for this standard. System disturbances in which relay loadability was a contributing factor, such as occurred on August 14, 2003, involve multiple contingencies without sufficient time for operator action. The drafting team notes that if manual adjustments were allowed between contingencies in criterion B4, this criterion would not identify any circuits subject to this standard except in cases where TPL-003 is violated. The test appropriately identifies circuits that may be loaded to levels that challenge relay settings when multiple contingencies occur. When such circuits are identified the Facility owner is required to meet relay loadability requirements to prevent the circuit from tripping unnecessarily before an operator has time to take corrective action. The drafting team respectfully points out that the Facility owner is not required to take any action to prevent overloads from occurring under such circumstances; the Facility owner is required only to provide relay loadability per the requirements in PRC-023 to mitigate the potential for such N-2 contingencies from leading to instability, uncontrolled separation, or cascading outages. The drafting believes that assigning selection of contingencies to the Planning Coordinator, and requiring Planning Coordinator consultation with the Facility owners regarding evaluation of post-contingency loading, is consistent with

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| the NERC Functional Model. | | | | |
| Brenda S. Anderson | Bonneville Power Administration | 6 | Negative | 1. BPA believes that there is a major discontinuity in the logical flow of the standard. As described in Section 4.2, the standard applies to certain transmission lines and transformers. In Requirement R1, there are thirteen criteria to select from "for any specific circuit terminal to prevent its phase protective relay settings from limiting transmission system loadability while maintaining reliable protection of the BES for all fault conditions". Of these thirteen criteria, only two apply to transformers--number ten and eleven. The way that these two are buried in between the other criteria that apply to line terminals and the way that they are written creates a question as to whether they apply to all transformers or only to transformers that are part of a transformer-terminated line. Additionally, since they are part of the group of thirteen criteria, of which only one must be selected, it appears that criteria ten and eleven can be ignored if another criterion is selected for a transformer-terminated line. BPA forsees this issue causing enough confusion among auditors and transmission owners that we cannot vote in favor of the standard until it is remedied. It would clear up the confusion if Criterion 10 was separated into two parts: one part that deals only with transmission line relays for transformer-terminated lines, and a second part that deals with load-responsive transformer relays. The second part--that deals with load-responsive transformer relays--should be moved along with Criterion 11 into a new requirement. This way, all of the criteria in Requirement 1 will apply only to line relays, with only one of the criteria needed to ensure that the line relays will not limit transmission system loadability. The new requirement (suggest using R2 and bumping the other requirements up a number) would deal specifically with load responsive transformer relays. Because this requirement would not be intermingled among the 13 optional criteria of Requirement 1, it would be clear that all load responsive transformer relays--not just those for transformer-terminated lines--were required to comply.<br>2. The drafting team has cleared up a major issue with Criterion 10.1 of Requirement 1 by clarifying that load responsive transformer relays must not expose a transformer to fault levels and durations that exceed the transformers mechanical withstand capability. This makes the requirement achievable, while the earlier version, which required that the relays not expose a transformer to fault levels and durations that exceeded its capability, was not. However, the mechanical withstand capability is not a well defined value, and the drafting |

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| | | | | team's use of a footnote to clarify this requirement is not sufficient. BPA agrees with the use of IEEE C57.109-1993 as the best way to define mechanical withstand capability, but if this is to be used as the measure of this requirement, it should be written into the requirement and not merely mentioned as a footnote. In addition, Clause 4.4, Figure 4 of IEEE C57.109-1993, as mentioned in the footnote, applies only to Category IV transformers. A close look at the standard reveals that the mechanical withstand capability curves for the other categories are not the same, and the requirements for these other categories must be identified as well. |
| **Response**: Thank you for your comments.<br>1. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that the structure of Requirement R1 is unchanged from the approved PRC-023-1 and is consistent with the "Zone 3" and "Beyond Zone 3" reviews completed by industry following the August 14, 2003 Northeast Blackout. The drafting team provided additional clarity specific to criterion 10 by splitting the fault protection aspect directed in the order (now part 10.1) from the relay loadability aspects. The drafting team believes that combining portions of criteria 10 and 11 at this time would add confusion by intermingling fault protective relays and overload relays. However, the drafting team will include your recommendations in the issues database for future consideration in the next general revision of the standard.<br>2. The drafting team believes that because the reference does not establish a requirement, rather it defines the phrase mechanical withstand capability, it is most appropriately included as a footnote rather than within Requirement R1, criterion 10. The drafting team also believes that a general citing of IEEE C57.109 within the requirements would be problematic in that we are only referencing a portion of the standard. The drafting team notes that the mechanical withstand is well-defined within the standard and that a specific reference to Clause 4.4, Figure from IEEE C57.109-1993 referenced in PRC-023-2 is sufficient. Category IV transformers are defined as transformers over 10,000 kVA (10 MVA) single-phase or 30,000 kVA (30 MVA) three-phase. Since this standard applies to BES facilities, the drafting team believes that the vast majority (if not all) of the applicable transformers will be Category IV transformers; if any Category III transformers fall within the applicability of this standard, the associated mechanical characteristic is virtually identical. | | | | |
| Robert Hirchak | Cleco Power LLC | 6 | Negative | Section 4.2 establishes the conditions to ultimately include the entire electric power infrastructure under the umbrella of protecting the "bulk electric system" which was originally defined as 200kV and above. Cleco is concerned this ever expanding regulatory umbrella is not justified. |
| **Response**: Thank you for your comment.<br>The drafting team believes that Section 4.2 will identify only those circuits that if they trip due to relay loadability, may contribute to undesirable system performance similar to what occurred during the August 14, 2003 blackout. The criteria developed in Attachment B were developed to achieve this purpose.<br>To the extent the commenter is concerned with the reference to facilities operated below 100 kV, the drafting team points out that consistent | | | | |

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| with the FERC position in Order 733-A we expect that references to circuits operated below 100 kV will have narrow applicability. The drafting team also notes that to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this the reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES." | | | | |
| Mark S Travaglianti | FirstEnergy Solutions | 6 | Affirmative | We applaud the drafting team for their diligent and expeditious work on responding to the FERC directives of Order 733. We support the standard but ask that the team clarify the effective dates. Compliance Application Notice CAN-0013 which was recently posted for industry comment correctly adds clarification to the actual effective date for (1) Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System; (2) Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System; and (3) Switch-on-to-fault schemes on all applicable facilities. Since this CAN specifies the date of October 1, 2013 in the U.S., we ask that the following sections of PRC-023-2 be revised to include this date: "5.1.1.1.3 For switch-on-to-fault schemes as described in PRC-023-2 - Attachment A, Section 1.3, the later of the first day of the first calendar quarter after applicable regulatory approval of PRC-023-2 or the first day of the first calendar quarter 39 months following applicable regulatory (October 1, 2013 in the U.S.) approval of PRC-023-1; or in those jurisdictions where no regulatory approval is required, the later of the first day of the first calendar quarter after Board of Trustees adoption of PRC-023-2 or July 1, 2011." and "5.1.2.1 The later of the first day of the first calendar quarter 39 months following notification by the Planning Coordinator (October 1, 2013 in the U.S.) of a circuit's inclusion on a list of circuits subject to PRC-023-2 per application of Attachment B, or the first day of the first calendar year in which any criterion in Attachment B applies." |
| **Response**: Thank you for your comments.<br><br>The drafting team acknowledges the complexity involved in the effective dates for this standard. The drafting team has reformatted the Effective Dates section of the standard into a tabular format consistent with CAN-0013 and has inserted the US effective date (October 1, 2013) where appropriate. | | | | |
| Thomas E Washburn | Florida Municipal Power Pool | 6 | Negative | The Regional Entity is not the correct entity to make decisions concerning what < 100 kV equipment is critical or not. It is too subject to inconsistent criteria being applied across the continent. It also is not in alignment with the regulatory construct of a stakeholder process described in Section 215 of the Federal Power Act which affords us the opportunity to learn from each other and develop better answers and solutions that appropriately balance costs, benefits and risks. Development of |

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| | | | | criteria and the application of that criteria ought to be a collaborative process continent-wide such that the criteria are applied consistently across the continent. This can be done separately, or as part of the BES definition effort currently underway. In the interim, many regions have Planning Coordinators that are not self-regulating, e.g., the Planning Coordinator is separate from the asset owners. Most of the Planning Coordinators are stakeholder organization whose "Planning Committees" would make the determination. For entities that do self-regulate, e.g., they are both the asset owner and Planning Coordinator, presumably the Regional Entity could form a stakeholder process with a Planning Committee whose members include appropriate and balanced representation from the stakeholders. These "Planning Committees" could be an alternative source for a stakeholder process to determine criteria for < 100 kV Applicability and apply that criteria while a continent-wide effort is underway to determine that criteria. These "Planning Committees" could remain in place to apply the continent-wide criteria to the regional system. |
| **Response**: Thank you for your comment.<br><br>The drafting team notes that PRC-023 does not grant the Regional Entity any authority, rather it reflects language already contained in the NERC Statement of Compliance Registry Criteria that provides for excluding from the registration list entities that do not own or operate "a transmission element below 100 kV associated with <u>a facility that is included on a critical facilities list that is defined by the Regional Entity</u> (emphasis added)." However, to provide additional clarification and alignment with the definition of Bulk Electric System (BES) presently under development, the drafting team has modified this reference in the standard to refer to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that are "part of the BES." | | | | |
| Silvia P. Mitchell | Florida Power & Light Co. | 6 | Negative | Objection to including Attachment B, without additional language. Currently, there is no provision in R6 that explains to the Transmission Owner, Generation Owner or Distribution Provider their right to challenge a determination under the NERC Rules of Procedure. Likewise, under the current language, a Planning Coordinator would have no understanding that its determination could be challenged. Concurrent with this ballot, NERC is soliciting comments on its new Rules of Procedure Section 1700, which will explains the challenge process. Hence, without the additional language proposed below that cross references the Rules of Procedure, PRC-023-2 does not appear to meet certain essential attributes listed in the NERC Rules of Procedures Section 302, such as (6) completeness and (8) clear language. Thus, to address this issue, the following language should be added as a new requirement 6.6: "Pursuant to Section 1700 of the NERC Rules of Procedure, a Transmission Owner, Generator or Distribution Provider may challenge a determination (made pursuant to requirement 6 (and its subparts)) that a facility it owns, in part or whole, is subject |

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| | | | | to compliance with PRC-023-2.” |
| **Response**: Thank you for your comment.<br>The drafting team notes that it would not be appropriate to include a Requirement 6.6 as proposed by the commenter because the proposed language is explanatory text and does not create a compliance obligation for any entity. The drafting team also notes that the reference to Section 302 of the Rules of Procedure is not relevant to including a reference to the appeals process in Section 1700. Note that Completeness is not at issue because a reference to the appeals process is not necessary to determine the required level of performance and Clear Language is not at issue because a reference to the appeals process is not required for responsible entities, using reasonable judgment and in keeping with good utility practices, to arrive at a consistent interpretation. Finally, the drafting team notes that entities have the right to appeal a decision of the Planning Coordinator regardless of whether such explanatory text is included in PRC-023-2. | | | | |
| Jessica L Klinghoffer | Kansas City Power & Light Co. | 6 | Negative | 1. The criteria with Attachment B is not consistent with the TPL planning standards and is likely to identify transmission facilities that do not pose a reliability threat to the operation of the interconnection. The criteria in Attachment B should focus on identifying transmission facilities that play a reliability role in maintaining equipment loadings within SOL and IROL facility ratings and not include other considerations such as flowgates which are a mechanism for energy market management.<br>2. In addition, the implementation time frames specified are not clear whether the implementation time frame of 24 months is an extension from the 18 month time frame for the RC to identify circuits using the criteria in Attachment B or if the 24 months is concurrent with the 18 months. Also, it is uncertain whether the 24 months will be sufficient without knowing the impact of the RC analysis. |
| **Response**: Thank you for your comments.<br>1. The criteria identified in Attachment B are consistent with, and developed specifically to address, the reliability concern driving the need for this standard. The drafting team continues to believe that Flowgates addressing reliability concerns for loading of circuits is an appropriate inclusion in these criteria. As noted in the NERC Glossary, “Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits.” This is reflected in the text of criterion B1 which is focused on circuits that are monitored Facilities of Flowgates; specifically, any circuit that is a monitored Facility of a permanent Flowgate, that has been included to address reliability concerns for loading of that circuit, as confirmed by the applicable Planning Coordinator. Concerns regarding loading of a circuit may be to prevent exceeding the Facility Rating or to prevent transfer levels that could lead to voltage violations or instability. To the extent that Flowgates are included for other purposes, criterion B1 would exclude monitored Facilities associated with those Flowgates.<br>2. The drafting team believes the commenter is referring to the time provided to a Facility owner to comply with PRC-023 after the Planning Coordinator identifies a circuit is subject to PRC-023-2 per application of Attachment B. The drafting team notes that in the previous posting of the standard this timeframe was extended from 24 months to 39 months. Specific to the commenter’s question, the standard identifies the 39 months are measured from “notification by the Planning Coordinator of a circuit’s inclusion on a list of circuits subject to | | | | |

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| PRC-023-2 per application of Attachment B." The 39 months in neither concurrent with nor an extension of the 18 months provided to the Planning Coordinator. | | | | |
| Daniel Prowse | Manitoba Hydro | 6 | Negative | Please see comments previously submitted by Manitoba Hydro regarding the effective date and the items included in Section 1.6 of Attachment A. |
| **Response**: Thank you for your comments.<br>1. The drafting team has considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1. Extending the timeframe included consideration of the number of circuits that may be identified by the Planning Coordinator.<br>2. Items included in Section 1.6 of Attachment A are included to address the concerns noted by FERC in Order 733. Settings for the protection schemes of concern are often very sensitive – well below load current – and dependent on the integrity of the communication channel to make a trip/no trip decision where other telecommunication system technologies require the operation of other protection system elements (usually distance elements) which are already subject to the requirements of this standard. Therefore, they will trip immediately due to load current upon the loss of communications, and are dependent on the fault detectors to inhibit trip which must therefore be secure regardless of how infrequently loss of communications may occur. | | | | |
| Marjorie S. Parsons | Tennessee Valley Authority | 6 | Affirmative | For Attachment B part B1: "Permanent flowgate" is too ambiguous. Most entities in the eastern interconnect use flowgates in many different processes such as EMS systems and state estimator, transfer capability calculations, congestion management processes, and market calculations. All of these processes have flowgates that could be considered "permanent". If this standard is pointing to the IDC Book of Flowgate (BOF) Permanent flowgates, then this should be so stated. However, since the IDC BOFs is not the most up to date list of flowgates, we suggest that a better line criticality identification to reliability is if a TLR has been called on the flowgate in the last two year. We recommend that instead of "permanent flowgate", the B1 portion of Attachment B1 should say " in the IDC Book of Flowgates and a TLR 3 or greater has been called on the flowgate in the last two years". |
| **Response**: Thank you for your comments.<br>The drafting team appreciates the suggestion to further refine the Flowgates of interest in the context of criterion B1. However, the drafting team believes that the Flowgates of interest must be determined based on the reliability basis for adding the Flowgate rather than historical transfers. Even if a TLR has not been called on a Flowgate for an extended period of time, during a system disturbance an overload on a monitored Facility comprising the Flowgate could lead to cascading outages if relay loadability requirements are not met. The drafting team believes it is best to continue to refer to circuits that are monitored Facilities of Flowgates that are included to address reliability concerns for | | | | |

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| loading of those circuits. | | | | |
| Larry D Grimm | Texas Reliability Entity | 10 | Negative | 1. In R1, criteria 10 and 11, the references to "operator established emergency transformer rating" should be changed to "owner established emergency transformer rating" to be consistent with R1. Note that FAC-008 and FAC-009 require the Transmission Owner and Generator Owner entities to establish Facility Ratings.<br>2. In R1, criteria 6, 7, 8, and 9, what is the definition of "remote to load", "remote from generation stations", "remote to the system", and "remote to the bulk system"? Also, the statement in criteria 7, 8, and 9, "under any system configuration", is extremely broad and will be difficult to plan for and enforce.<br>3. In R3, wording may present a possible conflict with FAC rating methodology, or should R3 be used as the FAC rating methodology in this case. What is the form of agreement required from the Planning Coordinator, Transmission Operator, and RC?<br>4. In R5, the TO, GO, and DP should also provide the updated list of circuits to the Transmission Planner, Planning Coordinator, and Reliability Coordinator as well as the Regional Entity.<br>5. Attachment A, Item 2. Consider including current differential protection systems that are designed to respond only to internal fault conditions and not overload conditions in the list of systems that are excluded from this standard.<br>6. Attachment B, B3. NUC-001 uses Generator Operator instead of plant owner.<br>7. Attachment B, B4.b. Suggest rewording as follows "For circuits operated between 100 kV and 200 kV, evaluate the post-contingency loading after contingency evaluations per TPL-003, Category A, B, and C3, in consultation with the Facility owner, against a threshold based on the Facility Rating assigned for that circuit and used in the power flow case by the Planning Coordinator." |
| **Response**: Thank you for your comments.<br>1. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that the phrase "operator established emergency transformer rating" is unchanged from the approved PRC-023-1. The drafting team will include your recommendation in the issues database for future consideration in the next general revision of the standard.<br>2. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team notes that Requirement R1, criteria 7, 8, and 9 are unchanged from the approved PRC-023-1. Additional explanation is provided in the Reference Document posted with standard PRC-023-1. | | | | |

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| 3. When an entity uses criterion 6, 7, 8, 9, 12, or 13 as the basis for verifying transmission line relay loadability, Requirement R3 should be used as the rating methodology for the relevant circuits. Agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator can be documented by evidence such as dated correspondence as noted in Measure M3. The drafting team will request this issue be added to the Issues Database for the FAC standards at such time they are to be revised.<br>4. The purpose of providing the information to the Regional Entity is for the ERO to make this information available, upon request, to users, owners, and operators of the Bulk Electric System, and directed in ¶224 of Order 733. The drafting team believes the proposed change is unnecessary since the Transmission Planner, Planning Coordinator, and Reliability Coordinator can request this information from the ERO.<br>5. The scope of Project 2010-13 is limited to addressing the FERC directives in Order 733. The drafting team will include your recommendation in the issues database for future consideration in the next general revision of the standard.<br>6. Plant owner has been changed to Generator Operator for consistency with NUC-001 as recommended by the commenter.<br>7. The drafting team believes that it is unnecessary to include Category A and B contingencies in criterion B4 since the loading would not exceed the Facility Rating except in cases of non-compliance with NERC Reliability Standards TPL-001 and TPL-002. Similarly, the drafting team has previously removed the reference to Category C contingencies because it resulted in confusion with some entities because the test required in criterion B4 is not the same as Category C3. The test specified in criterion B4 does not include manual system adjustments between contingencies. The drafting team notes that if manual adjustments were allowed between contingencies in criterion B4, this criterion would not identify any circuits subject to this standard except in cases where TPL-003 is violated. | | | | |

END OF REPORT