NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on Initial Ballot — Revisions to Relay Loadability for Order 733 (Project 2010-13)
Date of Initial Ballot: December 7-16, 2010

Summary Consideration: A 45-day formal comment period with a concurrent ballot during the last 10 days of the comment period was conducted for the Transmission Relay Loadability Version 2 standard PRC-023-2 from November 1, 2010 to December 1-16, 2010 and achieved a quorum of 88.00% and a weighted segment approval of 51.51%.

Commenters noted inconsistencies and redundancy between the Applicability section, Parts 6.1 and 6.2 of Requirement R6 and Attachment B. The drafting team agrees that inconsistency between these sections of the standard will lead to confusion. The drafting team has removed parts 6.1 and 6.2 from Requirement R6 to avoid redundancy, and has revised the Applicability section and Attachment B based on industry comments to provide consistency and clarity.

Commenters expressed concern that 24 months was not enough time to implement protection system modifications when the Planning Coordinator identifies circuits for which the applicable entity must comply with the standard. The drafting team considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1.

Commenters expressed concern with use of the phrase critical facilities for purposes of the Compliance Registry. The drafting team modified this reference related to circuits operated below 100 kV by replacing the phrase “critical for the purposes of the Compliance Registry” with text from ¶60 of Order No. 733, which references text in section III.d.2 of the NERC Statement of Compliance Registry Criteria. The second category of circuits to be evaluated now refers to transmission lines and transformers operated below 100 kV “that are included on a critical facilities list defined by the Regional Entity.”

Commenters expressed concern with criterion 10 citing that additional specificity is necessary to clarify a number of issues. In response to comments the drafting team added a footnote to criterion 10 to clarify that use of the phrase “mechanical withstand” is based on the “dotted line” in IEEE C57.109-1993 – *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4. The drafting team also moved the requirement for fault protection to a separate part of criterion 10 to clarify it applies only to load responsive transformer fault protection relays, and only when such relays are used.

Some commenters expressed concern that reporting associated with certain criteria under Requirement R1 duplicates requirements in FAC-008 and FAC-009. The drafting team explained that the FAC standards pertain to developing and transmitting ratings and rating methodologies, whereas PRC-023 requires notification when the certain Facility Ratings are used in assessing relay loadability

Some commenters expressed concern with complying with Requirement R2. The drafting team noted that Requirement R2 does not add a new obligation on Transmission Owners, Generator Owners, and Distribution Providers; it only explicitly states in PRC-023-2 an obligation that presently is included in Attachment A, Section 2 of PRC-023-1.

Some commenters questioned the need to differentiate between certain types communication-assisted protection systems. The drafting team noted that the distinction in Attachment A, Section 1.6 is appropriate, because current -differential telecommunications systems are different than other telecommunications systems, in that the sensitivities for the protection elements are often set very sensitively – well below load current – and depend on the integrity of the channel to make a trip/no trip decision where other telecommunication system technologies require the operation of other protection system elements (usually distance elements) which are already subject to the requirements of this standard. Therefore, they will trip immediately due to load current upon the loss of communications, and are dependent on the fault detectors to inhibit trip.

Many commenters expressed their belief that flowgates are market-based tools that are not appropriate for use in assessing system reliability. The drafting team responded that congestion and system reliability are not mutually exclusive concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. While flowgates are used to manage congestion, the underlying basis for doing so is to preserve system reliability. As such, it is appropriate and necessary to include monitored Facilities of flowgates as applicable circuits under PRC-023-2.

Commenters indicated clarification is needed to identify which Interconnection Reliability Operating Limits (IROLs) are to be considered in application of Attachment B, criterion B2. In response to several comments on this subject, the drafting team has replaced the reference to “determined in the long-term planning horizon” with “determined in the planning horizon pursuant to FAC-010”.

A number of commenters expressed concern that the description of transmission paths that supply off-site power to nuclear power plants lacked measurability. The drafting team has added a reference to Nuclear Plant Interface Requirements (NPIRs) developed pursuant to NUC-001. The drafting team also clarified that this criterion applies specifically to nuclear plants for the purpose of supporting nuclear plant safe operation and shutdown.

The drafting team received several comments regarding “going beyond” TPL requirements by not simulating manual system adjustment in between contingencies in Attachment B, criterion B4. The purpose of this criterion is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage if manual adjustments were not completed before the second contingency. The drafting team also clarified that while an assessment must be performed each year, the power flow analyses used to support the assessment need not be performed unless material changes to the system have occurred since the last assessment. The drafting team has added a footnote to criterion B4 to clarify this intent.

Commenters expressed concern that the criteria in Attachment B, criterion B5 in particular, provide too much autonomy to the Planning Coordinator. The drafting team added to some of the criteria that the Planning Coordinator shall consult with the Facility owner when performing its assessment to provide the Facility owner an opportunity for input into the assessment. Additionally, an appeals process will be included in the NERC Rules of Procedure so that a Facility owner may appeal a decision in the event it believes a circuit is incorrectly identified by the Planning Coordinator.

Several commenters expressed concern that Requirement R7 creates a potential for double jeopardy. The drafting team understands the double jeopardy concern and has deleted Requirement R7. The Effective Dates section has been modified to address the timeline in which Facility owners must comply with Requirements R1 and R5 when the Planning Coordinator identifies a circuit for which the Facility owner must comply with the standard.

One commenter requested that the exception for "switch on to fault" schemes be added back in. The drafting team understands the commenter’s concern that the proposed implementation plan for PRC-023-2 had the unintended consequence of shortening the time provided for Facility owners to comply with Requirement R1 for switch-on-to-fault schemes. The drafting team has modified the effective dates in the standard to address this problem.

A limited number of commenters expressed concern that the criteria for verifying relay loadability in Requirement R1 may not be directly applicable to circuits operated below 100 kV. The drafting team understands this concern and this item has been placed in the issues database for future consideration in the next general revision of the standard. The drafting team notes that PRC-023-1 already applies to lines operated at 100 kV to 200 kV and the drafting team does not believe that a significant number of sub-100 kV circuits will be impacted. As such, the drafting team disagrees that more research is required prior to implementing PRC-023-2.

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

Voter	Entity	Seg-ment	Vote	Comment
Roger C Zaklukiewicz		8	Negative	Concern with the possible interpretation of the wording in Requirement 1, Criteria 10. The wording needs to be clarified.
Response: Thank you for your comment. The text of the standard has been modified to clarify the intent of criterion 10. Specifically, a footnote has been added to criterion 10 to clarify that use of the phrase “mechanical withstand” is based on the “dotted line” in IEEE C57.109-1993 – *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4. The requirement for fault protection has been moved to a separate part of criterion 10 to clarify it applies only to load responsive transformer fault protection relays, and only when such relays are used.				
Edward P. Cox	AEP Marketing	6	Negative	The following comments are a subset of those submitted during the comment period. For more comprehensive commentary, please see the comments provided during the comment period. 1. R1's Criterion 10: American Electric Power sees two issues with R1's Criterion 10. First, transformer "mechanical withstand capability" is undefined, vague, and subject to various interpretations. The terminology used in this criterion must be more tightly defined to prevent ambiguity or else referenced to some agreed-upon standard such as IEEE C57.109-1993. Second, American Electric Power agrees that it is appropriate for the 150% and 115% settings criteria to apply to line relays terminated only with a transformer. However, Criterion 10 seems to assume that transmission line relays on transmission lines terminated with a transformer are also typically intended to protect the transformer. This is not normally or necessarily true. If the line relays are not intended to protect the transformer and as long as the transformer relaying properly protects the transformer from mechanical damage, there is no reason for Criterion 10 to apply to the line relays. To address these two deficiencies in Criterion 10, American Electric Power is providing proposed replacement language as part of its comments submission. 2. Sections 4.2.3, 4.2.6, 6.2, and the applicability portion of Attachment B: The wording
Brock Ondayko	AEP Service Corp.	5		
Paul B. Johnson	American Electric Power	1		
Raj Rana	American Electric Power	3		

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

				under Sections 4.2.3, 4.2.6, 6.2, and the applicability portion of Attachment B needs to be made consistent to avoid any misinterpretations and confusion. American Electric Power is providing proposed replacement language as part of its comments submission. 3. Requirement 7: Need to provide a 60-month timeline to implement the noted requirements for each facility that is added to the Planning Coordinator's initial list of facilities that must comply with this standard, versus the 24-month timeline to implement the noted requirements for each facility that is added to the Planning Coordinator's established list of facilities that must comply with this standard. This is a practical consideration that recognizes the high likelihood that the number of facilities that will be identified during development of the initial list of facilities will be many times greater than the incremental number of facilities that will be identified during the annual assessments and added to the established list of facilities. In addition, need to specify under this requirement whether any facilities that drop off the Planning Coordinator's list of facilities while still within the applicable (60-month or 24-month) implementation timeline must still comply with this standard. 4. Attachment A, Section 1.6: The wording of Attachment A, section 1.6 needs to be made consistent to avoid any confusion. American Electric Power is providing proposed replacement language as part of its comments submission. 5. Attachment B: Need to include a review and appeals process as part of the annual assessment for the Planning Coordinator to review the proposed facilities with the transmission entity prior to adding those facilities to the Planning Coordinator's list of facilities that must comply with the standard. American Electric Power is providing proposed replacement language as part of its comments submission.

Response: Thank you for your comments

1. The mechanical withstand is defined in IEEE C57.109-1993, *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, and a reference to this standard has been added as a footnote to address your concerns. The drafting team has modified the text of the standard to make the consideration of the mechanical withstand capability applicable to only the load responsive transformer fault protection relays, and only when such relays are used.
2. The drafting team agrees that inconsistency between these sections of the standard will lead to confusion. The drafting team has removed parts 6.1 and 6.2 from Requirement R6 to avoid redundancy, and has revised the Applicability section and Attachment B based on industry comments to provide consistency and clarity.
3. The drafting team has considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1.

4. Section 1.6 has been modified essentially as is suggested in the comment.
5. The drafting team has added to some of the criteria that the Planning Coordinator shall consult with the Facility owner when performing its assessment to provide the Facility owner an opportunity for input into the assessment. Additionally, an appeals process will be included in the NERC Rules of Procedure so that a Facility owner may appeal a decision in the event it believes a circuit is incorrectly identified by the Planning Coordinator.

Kirit S. Shah	Ameren Services	1	Negative	(1) Requirements R4 and R5 are already covered in Stanadrds FAC-008 and FAC-009. So they are redundant here and should be removed. (2) Section 6.2 is unclear and seems arbitrary in the statement ‘if the Regional Entity has indentified either of these Element types as critical facilities for the purpose of the Compliance registry’. A clear test is lacking. (3) Section 1.6 is contrary to section 2.0 and seems arbitrary. Why is a communication system for a current-based scheme treated to a higher standard than other communications scheme? The communications scheme reliability is covered through the maintenance and misoperations analysis standards. (4) Criterion B1, which has been modified to encompass only flowgates which have been included to address long-term reliability concerns, while a step in the right direction, does not go far enough. Because flowgates are primarily utilized to manage congestion and assist in the process of transmission service sales, rather than investigate reliability issues more appropriately conducted via study work covered under the TPL standards, this criteria should be eliminated. (5) Criterion B4 as worded still exceeds the requirements of Reliability Standard TPL-003 by requiring simulating double contingencies with no operator intervention permitted. While such simulation would be done as part of assessment work under TPL-003 for fast-acting contingencies involving multiple circuits, such as Category C1 bus faults, C2 breaker failures, and C5 double-circuit tower outages, such simulations are not necessary under TPL-003 with Category C3 events which consist of separate Category B events with intervening operator action. Such simulations should not be made necessary as part of the proposed PRC-023-2 standard. Rather, should the TPL-003 performance requirements not be met for Category C3 contingencies with operator intervention considered, those facilities could be included in the list of facilities specified in PRC-023-2 Requirement R6.
Mark Peters	Ameren Services	3		

Response: Thank you for your comments.

1. Providing this information to the specified entities addresses the potential for confusion as to the amount of time available to take corrective action. FAC-008 and FAC-009 do not address this issue. FAC-009 requires transmitting the Facility Rating, whereas PRC-023-2 requires notification when the relay loadability is based on a 15-minute rating.
2. The drafting team has removed parts 6.1 and 6.2 from Requirement R6 to avoid redundancy, and has revised the Applicability section and Attachment B (which used the same phrase) based on industry comments to provide clarity. The drafting team has replaced the phrase “critical for the purposes of the Compliance Registry” with text from ¶60 of Order No. 733, which references text in section III.d.2 of the NERC Statement of Compliance Registry Criteria. So the second category of circuits to be evaluated now refers to transmission lines and transformers operated below 100 kV “that are included on a critical facilities list defined by the Regional Entity.” The test by which the Regional Entity may make this determination is outside the scope of this standard.
3. Current-differential telecommunications systems are different than other telecommunications systems, in that the sensitivities for the protection elements are often set very sensitively – well below load current – and depend on the integrity of the channel to make a trip/no trip decision where other telecommunication system technologies require the operation of other protection system elements (usually distance elements) which are already subject to the requirements of this standard. Therefore, they will trip immediately due to load current upon the loss of communications, and are dependent on the fault detectors to inhibit trip.
4. Congestion and system reliability are not mutually exclusive concerns. The Interchange Distribution Calculator (IDC) was developed to address reliability concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. The IDC is intended to identify and unload critical circuits that could become overloaded due to transactions. While Flowgates and the IDC are used to manage congestion, the underlying basis for doing so is to preserve system reliability.

   The Flowgate Methodology defines that Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. If monitored Facilities of flowgates do not meet the Relay Loadability requirements in PRC-023, violation of physical system limitations could occur, leading to instability, uncontrolled separation, or cascading outages. As such, it is appropriate and necessary to include monitored Facilities of flowgates as applicable circuits under PRC-023-2.

   The drafting team acknowledges that Planning Coordinators do not decide which flowgates are included in the IDC; however, the NERC Functional Model does indicate that Planning Coordinators are responsible for coordinating transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators. Thus it is appropriate that Planning Coordinators, in applying the criteria in Appendix B, provide a screening as to whether the monitored Facilities of a flowgate are added to the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2.

   Based on a number of comments, the drafting team has modified criterion B1 to refer to “permanent” flowgates and has replaced the reference to “long-term reliability concerns” with “reliability concerns for loading of that circuit.” The drafting team believes this more clearly reflects the intent to exclude flowgates that are established on a temporary basis and more clearly identifies the role of the Planning Coordinator in applying criterion B1.
5. The drafting team received several comments regarding “going beyond” TPL requirements by not simulating manual system adjustment in between contingencies. The purpose of this criterion is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. As such, criterion B4 does not require that all double contingency combinations be tested. It also does not require that the loadings respect the published applicable ratings of the circuits. It does require that engineering judgment be used to select certain combinations of line outages to be studied without manual system adjustment to ensure that, if the manual adjustments were not completed before the second contingency, the relay settings on the lines remaining in service would not inappropriately trip the lines

Jason Shaver	American Transmission Company, LLC	1	Affirmative	Requirement R7 requires the Registered Entities to implement Requirement R1, Requirement R2, Requirement R3, Requirement R4, and Requirement R5 for each facility that the Planning Coordinator added to the list of facilities that must comply with this standard (per Requirement R6) by certain dates following notification by the Planning Coordinator. ATC believes it is difficult to determine without knowing the full scope of work. Until the Planning criteria can be determined, the scope is unknown. Assuming not many assets are added, two years would be a more reasonable amount of time.
Response: Thank you for your comments. The drafting team has considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1.				
Donald S. Watkins	Bonneville Power Administration	1	Negative	Please refer to formal BPA comments submitted for the period ending 12/16/10
Rebecca Berdahl	Bonneville Power Administration	3	Negative	Please refer to formal BPA comments submitted for period ending 12/16/10
Francis J. Halpin	Bonneville Power Administration	5	Negative	Please refer to BPA's formal comments submitted separately.
Brenda S. Anderson	Bonneville Power Administration	6	Negative	Please refer to formal BPA comments submitted for this comment period.
Response: Thank you for your comments. Please refer to the drafting team responses in the Consideration of Comments document.				
Gregory Van Pelt	California ISO	2	Negative	With regard to the questions asked in the comment form, the CAISO answers and comments are: Q1 - Yes Q2 - No comment from the PC perspective. The TOs are responsible for designing phase protection schemes appropriate to their systems. Q3 - No comment from the PC perspective. The facility owners are responsible Q4 - No comment from the PC perspective. The facility owners are responsible Q5 - No Comments: Wording for R 6.2 needs more clarity. Currently, only identifies the Regional Entity as identifying critical facilities. Believe it should also include the Planning Coordinator as an entity that may identify critical facilities operated below 100 kV. It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV that are part of the Bulk Electric System. This information is not readily available and there is no requirement for the Regional Entity to communicate this information to

				the Planning Coordinator. The concern is that inaction by the Regional Entity could cause the Planning Coordinator to be out of compliance with this requirement. Additional clarity is needed throughout requirement R6 and throughout the PRC-023-2 Standard. Q6 - No Comments: This requirement could be construed as potential for double jeopardy because failure to comply with Requirements 1-5 represent a violation of both Requirement 7 and Requirement 1-5. Q7 - Yes Q8 - No Comments: Additional clarity is needed in Attachment B and throughout the PRC-023-2 Standard.

Response: Thank you for your comments

Q1. Thank you for your comment

Q2. Thank you for your comment

Q3. Thank you for your comment

Q4. Thank you for your comment

Q5. The drafting team has removed parts 6.1 and 6.2 from Requirement R6 to avoid redundancy with the Applicability section and Attachment B. Within the Applicability section and Attachment B, a number of modifications have been made based on industry comments to improve clarity. The drafting team has replaced the phrase “critical for the purposes of the Compliance Registry” with text from ¶60 of Order No. 733, which references text in section III.d.2 of the NERC Statement of Compliance Registry Criteria, So the second category of circuits to be evaluated now refers to transmission lines and transformers operated below 100 kV “that are included on a critical facilities list defined by the Regional Entity.” The drafting team believes it is necessary to maintain consistency with the NERC Statement of Compliance Registry Criteria for the Regional Entity to develop a critical facilities list, and then have the Planning Coordinator apply the criteria in Attachment B to determine for which of the circuits on the list the applicable entities must comply with the standard. While the drafting team acknowledges there is no requirement for the Regional Entity to provide the list, the drafting team believes the Regional Entity will make a critical facilities list available as it is necessary for other entities to have this information to support reliable operation of the interconnected transmission grid.,

Q6. The drafting team understands the double jeopardy concern and has deleted Requirement R7. The Effective Dates section has been modified to address the timeline in which Facility owners must comply with Requirements R1 and R5 when the Planning Coordinator identifies a circuit for which the Facility owner must comply with the standard.

Q7. Thank you for your comment

Q8. Extensive revisions were made to Attachment B and throughout the standard to improve clarity.

Paul Rocha	CenterPoint Energy	1	Negative	CenterPoint Energy has several concerns with this proposed Standard. CenterPoint Energy's main concern is with the criteria in Attachment B used to determine which facilities must comply. 1. We do not agree with criterion B4 that a percent loading is a technically sound basis to indicate if a facility is operationally significant. CenterPoint Energy recommends the threshold be revised to apply to those facilities that the loss of which would risk cascading outages or voltage collapse. 2. Criterion B3 indicates any path that is used to supply off-site power to nuclear plants, as agreed to by the plant owner and the Transmission Entity. If the purpose of attachment B is to provide "bright line" criteria, then a negotiated agreement would not qualify as "bright line". Additionally, off-site power requirements are meant to ensure safe shutdown of nuclear reactors in a system restoration event where transmission lines are lightly loaded. CenterPoint Energy recommends it be deleted. 3. CenterPoint Energy recommends criterion B5 be deleted, as it is too broad and gives the PC too much discretion in determining other facilities which must comply with this Standard. In addition, CenterPoint Energy believes Transmission Planners should have a role in the determination of which facilities must comply with this standard. 4. The use of the term "critical" in R6 is problematic, as it can cause confusion with NERC CIP Standards which require the facility owner to determine Critical Assets. CenterPoint Energy recommends using "operationally significant" wherever "critical" is used.

Response: Thank you for your comments.

1. The purpose of the criteria in Attachment B is to identify circuits that present a risk of cascading outages if relay loadability requirements are not met. Applying criterion B4 only to circuits for which their loss would risk cascading outages or voltage collapse would create circularity in the assessment by requiring the Planning Coordinator to know the outcome before applying the criteria.
2. In response to comments on criterion B3 the drafting team has modified the criterion to refer explicitly to "the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001." The drafting team believes this modification to criterion B3 provides a level of measurability that should address the commenter's concern.
3. The drafting team has modified criterion B5 in response to industry comments to require that if the Planning Coordinator selects a circuit based on technical studies or assessments, other than those specified in criteria B1 through B4, that such selection is to be made in consultation with the Facility owner to provide the Facility owner an opportunity for input into the assessment. Additionally, an appeals process will be included in the NERC Rules of Procedure so that a Facility owner may appeal a decision in the event it believes a circuit is incorrectly identified by the Planning Coordinator. The drafting team believes

the Planning Coordinator is the NERC Functional Model entity with the wide-area view and study expertise necessary to perform the assessment in Attachment B. The drafting team also notes that assigning this responsibility solely to the Planning Coordinator is consistent with the approved PRC-023-1 and FERC Order No. 733. 4. The context in which the term “critical” is used is different than in the NERC “Zone 3” and “Beyond Zone 3” reviews. The remaining references to the term critical are in the context of NERC Statement of Compliance Registry Criteria. Rather than using the term “operationally significant,” the drafting team has replaced the phrase “critical for the purposes of the Compliance Registry” with text from ¶60 of Order No. 733, which references text in section III.d.2 of the NERC Statement of Compliance Registry Criteria, so the second category of circuits to be evaluated now refers to transmission lines and transformers operated below 100 kV “that are included on a critical facilities list defined by the Regional Entity.” The drafting team made corresponding modifications to the Applicability section.				
Shamus J Gamache	Central Lincoln PUD	4	Negative	Central Lincoln supports the Pacific Northwest Small Public Power Group comments: 1. The comment group finds R1.10 very confusing when attempting to understand it in the context of IEEE C57.109-1993. C57.109 identifies a solid curve as the thermal damage curve, while a dotted dog leg is the mechanical damage curve. Generally the dog leg is only considered for those class II and III transformers subjected to frequent through faults and all class IV transformers. Is the intent of the SDT to require this level of protection for all transformers regardless of through fault frequency and/or transformer class? If the SDT really meant to protect transformers from thermal or combination damage, please note that it is not possible to completely protect transformers from the thermal damage of low current long duration faults while still complying with the 150% of maximum rating. The thermal damage curve extends down to twice the base current. A footnote in C57.109 states that base current is established from the lowest nameplate kVA rating. A typical transformer with two stages of cooling will have a high nameplate rating of 1.67 times this base rating. The first bullet of R1.10 states affected entities must allow 1.5 times the maximum, so we are up to 2.5 times the base rating. Since we must allow this much without tripping, the relay must be set even higher. 1.2 times would be a secure margin, so the relay is set to pickup at 3 times the base rating. This setting would of course violate the first part of R1 criterion 10 because the transformer’s fault capability would be exceeded for faults between 2 and 3 times the base rating. 2. We also note that criterion 11 is apparently an exception to criterion 10, but this is not altogether clear since 10 is for fault protection while 11 is for overload protection. Please rewrite this (these) criterion (criteria) to clarify the SDT’s intent(s). 3. We thank the SDT for addressing our concern regarding radially operated circuits. We

				note, however, that the key word "operated" from the consideration of comments was dropped before it reached the standard. Please change the last bullet of B4 to: Radially operated circuits serving only load are excluded.

Response: Thank you for your comments.

1. The drafting team has clarified this requirement by making it a separate part of criterion 10 and by indicating this criterion applies to load responsive transformer fault protective relays, if used. A footnote has been added to criterion 10 to clarify this requirement is based on the "dotted line" in IEEE C57.109-1993 – *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4. The drafting team notes that 150 percent of a typical maximum transformer nameplate rating is on the order of 250 percent (150 percent x 1.67) of the base nameplate rating. The vertical portion of the mechanical withstand curve is defined by 1/(2xZt), which for a transformer with 12 percent impedance is approximately 400 percent of the nameplate base rating, allowing protection to be set above the loadability requirement in criterion 10 and below the transformer mechanical withstand curve
2. Criterion 10 and Criterion 11 are meant to address separate applications. Criterion 10 addresses fault protection relays and their response to load; Criterion 11 explicitly addresses thermal overload protection.
3. The drafting team agrees with your comment and has modified criterion B4 accordingly.

Timothy Beyrle	City of New Smyrna Beach Utilities Commission	4	Affirmative	• R1 and R2 have binary VSLs where they should be percentages of all relays that need to meet the standard based on statistical sampling.

Response: Thank you for your comments.

The VSLs defined are consistent with the VSLs already approved by FERC in PRC-023-1.

Chang G Choi	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	1	Negative	1. Transmission or Transformers that normally would not be considered BES assets are subject to inclusion by the Planning Coordinator. The criteria for inclusion have not been developed yet.

Max Emrick	City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	5		2. Attachment A Section 1.6 was added due to FERC Order 733, but it is still vague what includes “Supervisory Elements”. Please clarify supervisory elements (Does it include RTUs?) 3. Detailed direction about relay setting methodology could be expanded to 110-kV level by this revision. Much more research should be devoted to such detailed changes to evaluate impact to other protection and operation constraints, before such settings are mandatory. 4. The new requirement (R2) may present conflicting choices for a relay engineer, since out-of-step blocking is technically challenging to set, sense and discriminate from certain loading and fault conditions.
Response: Thank you for your comments. 1. The NERC Statement of Compliance Registry Criteria permits application of NERC Reliability Standards to certain facilities operated below 100 kV, such as for transmission elements operated below 100 kV that are included on a critical facilities list defined by the Regional Entity. The test by which the Regional Entity may make this determination is outside the scope of this standard. The criteria by which the Planning Coordinators determine for which of the circuits on the list the applicable entities must comply with the standard are defined in Attachment B. 2. Attachment A, Section 1.6 has been modified to include supervisory elements only as they apply to current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications. The drafting team believes this modification provides clarity that this section does not apply to RTUs and other applications. 3. The drafting team understands your concern and will place this item in the issues database for future consideration in the next general revision of the standard. However, the drafting team notes that PRC-023-1 already applies to lines operated at 100 kV to 200 kV and the drafting team does not believe that a significant number of sub-100 kV circuits will be impacted. As such, the drafting team disagrees that more research is required prior to implementing PRC-023-2. 4. The drafting team notes that Requirement R2 does not add a new obligation on Transmission Owners, Generator Owners, and Distribution Providers; it only explicitly states in PRC-023-2 an obligation that presently is included in Attachment A, Section 2 of PRC-023-1.				
Randall McCamish	City of Vero Beach	1	Affirmative	R1 and R2 have binary VSLs where they should be percentages of all relays that need to meet the standard based on statistical sampling.
Response: Thank you for your comments. The VSLs defined are consistent with the VSLs already approved by FERC in PRC-023-1.				
Michelle A Corley	Cleco Corporation	3	Negative	Cleco respectfully disagrees with NERC by establishing a Standard which mandates how we should set protective relays. It is our intention to establish relay settings which safely protect the public and facilities. If prudent engineering practice results in a relay becoming the limiting element within a facility, the facility rating should be adjusted as is specified in FAC-008. Relays should not be treated any different than other elements when rating a facility. If system studies show the facility is overloaded, then the utility can decide how best to increase the rating.
Stephanie Huffman	Cleco Power	5		
Danny McDaniel	Cleco Power LLC	1		

Robert Hirchak	Cleco Power LLC	6		
Response: Thank you for your response. Your comment is largely related to the existing approved PRC-023-1; this standard results from observations wherein protective relay loadability was heavily complicit with the 2003 blackout and numerous other major system disturbances, resulting in an acknowledged need to define appropriate criteria.				
Paul Morland	Colorado Springs Utilities	1	Negative	CSU provides the following comment: The documentation for PRC-023 seems to rely quite heavily on the usage of spread sheets and and calculations (with the possibility of having bad formulas). Some engineers who rely on graphical methods from coordination software may be less likely to have "bad formula" issues. There seems to be a bias in this standard to the formula based spreadsheet, where there is no mention of guidelines for those spreadsheets or a NERC provided spreadsheet.
Response: Thank you for your comment. It is left to each entity to determine how to implement the standard and document compliance. The Measures in the standard are only examples of the types of documentation that may be considered acceptable evidence.				
Donald E. Nelson	Commonwealth of Massachusetts Department of Public Utilities	9	Abstain	Criteria 10 under requirement 1 needs to be clarified so that the full implication is completely understood.
Response: Thank you for your comments. The text of the standard has been modified to clarify the intent of criterion 10. Specifically, a footnote has been added to criterion 10 to clarify that use of the phrase "mechanical withstand" is based on the "dotted line" in IEEE C57.109-1993 – *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4. The requirement for fault protection has been moved to a separate part of criterion 10 to clarify it applies only to load responsive transformer fault protection relays, and only when such relays are used.				
Christopher L de Graffenried	Consolidated Edison Co. of New York	1	Negative	1. R1 - Clarification is needed on whether criterion 10 requires a transformer to have load responsive protection to protect from mechanical damage. The wording in criterion 10 should be changed to "set transformer fault protection relay or transmission line relay on transmission line terminated with only a transformer." Is this criterion requiring that a transformer with only differential protection and no other load responsive remote protection be mitigated with additional load responsive protection? The loading on phase angle regulators, and series reactors should also be considered and mentioned. 2. Also, there appears to be words missing in criterion 9 of R1: "the maximum current flow from the ? to the ? under any system configuration."
Peter T Yost	Consolidated Edison Co. of New York	3		
Wilket (Jack) Ng	Consolidated Edison Co. of New York	5		

Nickesha P Carrol	Consolidated Edison Co. of New York	6		3. R2 - What is the expectation for verifying that the out-of-step (OOS) blocking elements allow tripping of phase protection relays for faults that occur during the loading conditions used to verify transmission line relay loadability? It would be costly and time consuming to verify this. To comply with this requirement, utilities may have to remove OOS protections all together. 4. Attachment B - Why does B3 only apply to Nuclear Power Plants only?
Response: Thank you for your comments. 1. The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point. 2. The text has been corrected. 3. The drafting team believes that this requirement will be met by a planning analysis of the settings. This is not a new requirement. PRC-023-1 requires that this analysis be done within Attachment A. 4. This criterion applies specifically to nuclear plants for the purpose of supporting nuclear plant safe operation and shutdown. The drafting team believes the added reference to the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001 better reflects this intent.				
David Frank Ronk	Consumers Energy	4	Negative	We have the following comment on the revisions, specifically sub-requirement R1.12a, which states, "Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer.". We have no issue with this requirement on transmission lines that are 200 kV or greater. However, we do have a concern with applying requirement R1.12a on lower voltage lines now that the Transmission Relay Loadability Standard is being revised to included selected equipment 200 kV and below. The positive-sequence line angle on lower voltage lines, such as 69 kV or 46 kV, is significantly lower than 90 degrees. The positive-sequence line angle for 3/0 ACSR, for example, is only 55 degrees. Setting a 90 degree MTA on these lines would require a much larger reach setting to provide adequate line protection. In some cases, especially for lines with long spurs and poor line conductor, the increased reach setting may actually provide less loadability than a reach setting based on an MTA set at the positive-sequence line angle. A 90 degree MTA also dramatically reduces the resistive fault coverage for these lines. For these reasons, we would propose a modification to sub-requirement R1.12a as follows: Set the maximum torque angle (MTA) to 90 degrees or the highest supported by the manufacturer on 200 kV or greater transmission lines. Set the maximum torque angle (MTA) to the positive-sequence line angle on transmission lines less than 200 kV.
James B Lewis	Consumers Energy	5		
Response: Thank you for your comments. The drafting team understands your concern and will place this item in the issues database for future consideration in the next general revision of the standard.				

Russell A Noble	Cowlitz County PUD	3	Negative	1. The comment group that Cowlitz PUD coordinated comments with finds R1.10 very confusing when attempting to understand it in the context of IEEE C57.109-1993. C57.109 identifies a solid curve as the thermal damage curve, while a dotted dog leg is the mechanical damage curve. Generally the dog leg is only considered for those class II and III transformers subjected to frequent through faults and all class IV transformers. Is the intent of the SDT to require this level of protection for all transformers regardless of through fault frequency and/or transformer class? If the SDT really meant to protect transformers from thermal or combination damage, please note that it is not possible to completely protect transformers from the thermal damage of low current long duration faults while still complying with the 150% of maximum rating. The thermal damage curve extends down to twice the base current. A footnote in C57.109 states that base current is established from the lowest nameplate kVA rating. A typical transformer with two stages of cooling will have a high nameplate rating of 1.67 times this base rating. The first bullet of R1.10 states affected entities must allow 1.5 times the maximum, so we are up to 2.5 times the base rating. Since we must allow this much without tripping, the relay must be set even higher. 1.2 times would be a secure margin, so the relay is set to pickup at 3 times the base rating. This setting would of course violate the first part of R1 criterion 10 because the transformer's fault capability would be exceeded for faults between 2 and 3 times the base rating. 2. We also note that criterion 11 is apparently an exception to criterion 10, but this is not altogether clear since 10 is for fault protection while 11 is for overload protection. Please rewrite this (these) criterion (criteria) to clarify the SDT's intent(s). 3. We thank the SDT for addressing our concern regarding radially operated circuits. We note, however, that the key word "operated" from the consideration of comments was dropped before it reached the standard. Please change the last bullet of B4 to: Radially operated circuits serving only load are excluded.
Rick Syring	Cowlitz County PUD	4		
Bob Essex	Cowlitz County PUD	5		

Response: Thank you for your comments.

1. The drafting team has clarified this requirement by making it a separate part of criterion 10 and by indicating this criterion applies to load responsive transformer fault protective relays, if used. A footnote has been added to criterion 10 to clarify this requirement is based on the "dotted line" in IEEE C57.109-1993 – *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration*, Clause 4.4, Figure 4. The drafting team notes that 150 percent of a typical maximum transformer nameplate rating is on the order of 250 percent (150 percent x 1.67) of the base nameplate rating. The vertical portion of the mechanical withstand curve is defined by 1/(2xZt), which for a transformer with 12 percent impedance is approximately 400 percent of the nameplate base rating, allowing protection to be set above the loadability requirement in criterion 10 and below the transformer mechanical

withstand curve. 2. Criterion 10 and Criterion 11 are meant to address separate applications. Criterion 10 addresses fault protection relays and their response to load; Criterion 11 explicitly addresses thermal overload protection. 3. The drafting team agrees with your comment and has modified criterion B4 accordingly.				
Michael F Gildea	Dominion Resources Services	3	Affirmative	5.1 Requirement R1. Dominion would like to see the exception of "switch on to fault" schemes added back in.
Response: Thank you for your comments. The drafting team understands the commenter's concern that the proposed implementation plan for PRC-023-2 had the unintended consequence of shortening the time provided for Facility owners to comply with Requirement R1 for switch-on-to-fault schemes. The drafting team has modified the effective dates in the standard to address this problem.				
Henry Ernst-Jr	Duke Energy Carolina	3	Negative	Duke Energy appreciates the work of the drafting team, but believes additional changes are needed before voting to approve PRC-023-2. 1. R6.1 and R6.2 unnecessarily duplicate the first part of Attachment B, and should be deleted from R6. 2. R6.3 and R6.4 are both associated with maintaining the list and should be combined into a separate requirement (new R7), with its own VRF and VSLs. Including the year for a facility should apply to all the criteria, not just B4. Suggested wording for new R7: "Maintain a list of circuits that must comply with this standard due to meeting Attachment B criteria. For each circuit, include the applicable criteria and the year studied for which the criteria first applies, when a facility is added to the list." 3. R6.5 should become a new R8 with its own VRF and VSLs. No wording changes needed. 4. Since the Attachment B criteria are applied beyond the operating horizon, R7 should be rewritten (and also renumbered as R9). Suggested wording: " Each Transmission Owner, Generator Owner, and Distribution Provider shall implement Requirement R1, Requirement R2, Requirement R3, Requirement R4, and Requirement R5 for each facility that is added to the Planning Coordinator's list of facilities that must comply with this standard pursuant to Requirement R6, by the first day of the first calendar quarter of the year in which Attachment B criteria first apply. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]

				5. B2 needs additional clarification, because identification could be in the short term or long term planning horizon. Suggested rewording: “B2. Each circuit that is a monitored Element of an IROL where the IROL was determined beyond the operating horizon.” 6. B3 needs additional clarification, to explicitly identify the necessary agreement between the plant owner and Transmission Entity. Suggested rewording: “Each circuit that forms a path (as agreed to by the plant owner and the Transmission Entity pursuant to NUC-001) to supply off-site power to nuclear plants.
Response: Thank you for your comments. 1. R6.1 and R6.2 have been removed from PRC-023-2 in response to comments. 2. The drafting team believes that it is appropriate to include details regarding maintenance of the list as a part of Requirement R6 consistent with the existing standard PRC-023-1. While the drafting team disagrees that parts 6.3 and 6.4 should become a separate requirement, the drafting team has combined these into one part of Requirement R6 consistent with the commenter’s recommendation. The combined text, now part 6.1, reads: “6.1 Maintain a list of circuits operated below 200kV and subject to the standard per application of Attachment B, which includes the first calendar year in which any criterion in Attachment B applies.” 3. The structure of the standard text within R6 including the approved VRFs and VSLs is similar to R3 in PRC-023-1, and therefore it is beyond the scope of the project to modify this structure. 4. The drafting team notes that Requirement R7 has been deleted in response to other comments. The Effective Dates section has been modified to address the timeframe in which Facility owners must comply with Requirements R1 through R5 when the Planning Coordinator identifies a circuit for which the Facility owner must comply with the standard. 5. In response to several comments on this subject, the drafting team has replaced the reference to “determined in the long-term planning horizon” with “determined in the planning horizon pursuant to FAC-010.” 6. In response to comments on criterion B3 the drafting team has modified the criterion to refer explicitly to “the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001.”				
Chuck B Manning	Electric Reliability Council of Texas, Inc.	2	Negative	ERCOT ISO has filed comments through the online form. Please reference filed comments for details.
Response: Thank you for your comments. Please refer to the drafting team responses in the Consideration of Comments document.				
Robert Martinko	FirstEnergy Energy Delivery	1	Negative	Please see FirstEnergy's comments submitted separately through the comment period posting.
Kevin Querry	FirstEnergy Solutions	3		
Mark S Travaglianti	FirstEnergy Solutions	6		

Response: Thank you for your comments. Please refer to the drafting team responses in the Consideration of Comments document.				
Frank Gaffney	Florida Municipal Power Agency	4	Affirmative	R1 and R2 have binary VSLs where they should be percentages of all relays that need to meet the standard based on statistical sampling.
David Schumann	Florida Municipal Power Agency	5		
Richard L. Montgomery	Florida Municipal Power Agency	6		
Thomas W. Richards	Fort Pierce Utilities Authority	4		
Response: Thank you for your comments. The VSLs defined are consistent with the VSLs already approved by FERC in PRC-023-1.				
Ajay Garg	Hydro One Networks, Inc.	1	Negative	Hydro One is casting a negative vote with the following comments: PRC-023-2 addresses the Phase I directives from FERC Order 733 including a process for use in determining which facilities (transmission lines operated below 200 kV and transformers with low voltage terminals connected below 200 kV) must meet specific relay loadability criteria. Category B4 in the criteria is intended to identify 100 kV to 200 kV lines that will experience different degrees of thermal overload with respect to their Facility Rating for different loading duration. Since these durations may be as long as several hours, it is unreasonable to impose the restriction of "without manual system adjustment in between (the two contingencies)" on the B4 test procedure. Aside from this restriction, the degree of thermal overload with respect to Facility Rating (of various loading durations) is not a relevant measure of the significance of that overload for the reliability of the system. The correct measure is whether tripping of the overloaded line, either by manual operator action (along with other system adjustments that would be available during the relevant time period) or as a consequence of protection and control actions, would result in cascaded tripping of other bulk transmission lines.
David L Kiguel	Hydro One Networks, Inc.	3		
Response: Thank you for your comments. Circuits subject to loading in excess of their emergency rating are susceptible to tripping, which could lead to instability, uncontrolled separation, or cascading outages. The drafting team believes it is impractical to expect the Planning Coordinator to anticipate and assess every possible system situation that could lead to these conditions. Thus the criteria in Attachment B were selected to identify circuits that present a risk of cascading outages if relay loadability requirements are not met. The drafting team has added to some of the criteria that the Planning Coordinator is to consult with the Facility owner when performing its assessment to provide the Facility owner an opportunity for input into the assessment. Additionally, an appeals process will be included in the NERC Rules of Procedure so that a Facility owner may appeal a decision in the event it believes a circuit is incorrectly identified by the Planning Coordinator.				

Kim Warren	Independent Electricity System Operator	2	Negative	Clarification is needed on whether criterion 10 requires a transformer to have load responsive protection to protect from mechanical damage. The wording in criterion 10 should be changed to "set transformer fault protection relay or transmission line relay on transmission line terminated with only a transformer." Is this criteria requiring that a transformer with only differential protection and no other load responsive remote protection be mitigated with additional load responsive protection?
Response: Thank you for your comments. The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point.				
Michael Moltane	International Transmission Company Holdings Corp	1	Negative	ITC votes "Negative" on this ballot for the following reasons: R2: ITC is not clear that we can provide the documentation required to provide evidence that an OSB element will, with heavy load, allow tripping. Out of step relaying is based on a moving impedance locus for a swing versus a fault. Different relays will operate differently and in some relays there is a small period of time, 2 seconds, where heavy loads will block tripping. Is the requirement trying to say that the out of step blocking element must never pick up and block for unusually heavy loads or is there more to it? This requirement is too restrictive and does not allow for engineering judgment for out of step protection. The drafting team must provide guidance on how to meet this requirement? We are concerned that an unusually heavy load swing will appear to the correct OSB setting as a swing and prevent tripping for a short time. Setting OSB relays per the new R2 to allow tripping for these severe and highly improbable conditions may remove blocking for the actual predicted swings and have a worse effect on the BES. R7: When this new criteria goes into effect, circuits will become designated as "Critical" that were not before. There must be adequate time allowed for utilities to budget, engineer and construct new relay systems to meet this standard. Some medium voltage lines may need to be re-terminated and will require a significant amount of time to get planned and constructed. We suggest an implementation time of 36 months after identification by the planning coordinator.
Response: Thank you for your comment. R2: The drafting team notes that Requirement R2 does not add a new obligation on Transmission Owners, Generator Owners, and Distribution Providers; it only explicitly states in PRC-023-2 an obligation that presently is included in Attachment A, Section 2 of PRC-023-1. R7: The drafting team has considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1.				

Kathleen Goodman	ISO New England, Inc.	2	Negative	ISO New England is voting no for the following reasons: B2. Item B2 adds significant confusion to the process. The long term planning horizon may include transmission projects which have not even been built or alternative system configurations which do not exist, making it impossible for affected parties to set their relays appropriately. Suggested replacement language to avoid this issue: "Each circuit that is a monitored element of an IROL, assuming that all transmission elements are in service and the system is under normal conditions." B3. This item indicates that the circuits to be considered are to be agreed to by the plant owner and the Transmission Entity. Attachment B is applicable to the Planning Coordinator. If this item is by agreement by the plant and the Transmission Entity it should be removed from Attachment B and placed elsewhere in the document. If this is intended to apply to the Planning Coordinator, Transmission Entity should be replaced with Planning Coordinator. Why does B3 only apply to Nuclear Power Plants? B4. This criterion is overly stringent and should be deleted. The system is neither planned nor operated to allow for two overlapping outages without operator action in between. If this criterion is retained, it should be made consistent with the requirements of TPL-003 where operator actions can be assumed between the first and second contingencies. Since a similar comment was made previously, more information is being provided following. 1. Since the system is neither planned nor operated to two overlapping outages in between, such testing may result in unsolved cases, or voltages well below criteria. In the case of an unsolved case, there are no flows to evaluate, making this standard impossible to apply. In the case of a solved case with voltages well below criteria, currents are likely to be incredibly high and therefore viewed as unrealistic. These concerns may limit the contingency selection to those which are not severe, eliminating any perceived benefit from this testing. 2. There is no guidance provided on how the system should be dispatched in the model upon which the overlapping contingencies are tested. This will result in significant discrepancies between the base assumptions used by the various Planning Coordinators. The contents of this standard should be reviewed to reflect the new definition of the Bulk Electric System.
Response: Thank you for your comments.				

<table>
<tr><td colspan="5">B2: In response to several comments on this subject the drafting team has replaced the reference to “determined in the long-term planning horizon” with “determined in the planning horizon pursuant to FAC-010.”

B3: This criterion applies to the Planning Coordinator and requires that the Planning Coordinator include circuits that form a path “(as agreed to by the plant owner and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001” on the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2.
This criterion applies specifically to nuclear plants for the purpose of supporting nuclear plant safe operation and shutdown. The drafting team believes the added reference to the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001 better reflects this intent.

B4: The drafting team received several comments regarding “going beyond” TPL requirements by not simulating manual system adjustment in between contingencies. The purpose of this criterion is not to assess whether the system performance meets the TPL standard, rather, it is to be used as a screen to determine whether the relay loadability settings are properly set such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. As such, B4 does not require that all double contingency combinations be tested. It also does not require that the loadings respect the published applicable ratings of the circuits. It does require that engineering judgment be used to select certain combinations of line outages to be studied without manual system adjustment to ensure that, if the manual adjustments were not completed before the second contingency, the relay settings on the lines remaining in service would not inappropriately trip the lines. This standard, like all others, will need to be reviewed when a new definition of the Bulk Electric System is approved.</td></tr>
<tr><td>Michael Gammon</td><td>Kansas City Power & Light Co.</td><td>1</td><td rowspan="3">Negative</td><td rowspan="3">Attachment B is duplicative to the criteria established in the TPL planning standards and can be conflicting regarding the identification of critical circuits by Planning Authorities and Transmission Planners. Removal of Attachment B is recommended and replace with language that specifies facilities 100kv and above identified by Planning Authority or by the Transmission Planner are applicable to the Standard.</td></tr>
<tr><td>Charles Locke</td><td>Kansas City Power & Light Co.</td><td>3</td></tr>
<tr><td>Jessica L Klinghoffer</td><td>Kansas City Power & Light Co.</td><td>6</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.

Attachment B is not duplicative of the criteria established in the TPL planning standards, nor does it conflict with any responsibilities of Planning Coordinators (formerly Planning Authorities) or Transmission Planners. The purpose of the criteria in Attachment B is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. The introductory sentence in Attachment B has been revised to clarify the implication of identifying circuits per all criteria in the attachment: “If any of the following criteria apply to a circuit, the applicable entity must comply with the standard for that circuit.” These criteria provide a consistent methodology for Planning Coordinators to perform the determination presently assigned in Requirement R3 of PRC-023-1 (now Requirement R6 in PRC-023-2). This requirement supports the reliability purpose of this standard by identifying the circuits below 200 kV which could lead to cascading outages, if Protection Systems are not set according to the relay loadability requirements.</td></tr>
<tr><td>Stan T. Rzad</td><td>Keys Energy Services</td><td>1</td><td rowspan="2">Affirmative</td><td rowspan="2">R1 and R2 have binary VSLs where they should be percentages of all relays that need to meet the standard based on statistical sampling. But that doesn't seem to be that big a deal</td></tr>
<tr><td>Walt Gill</td><td>Lake Worth Utilities</td><td>1</td></tr>
</table>

Response: Thank you for your comments. The VSLs defined are consistent with the VSLs already approved by FERC in PRC-023-1.				
Joe D Petaski	Manitoba Hydro	1	Negative	Please see comments submitted by Manitoba Hydro in the formal comment period.
Greg C. Parent	Manitoba Hydro	3		
S N Fernando	Manitoba Hydro	5		
Daniel Prowse	Manitoba Hydro	6		
Response: Thank you for your comments. Please refer to the drafting team responses in the Consideration of Comments document.				
Terry Harbour	MidAmerican Energy Co.	1	Negative	1) The Attachment B criteria for determining what circuits must follow PRC-023 according to FERC Order 733 and paragraph 69 specifying tests to determine what facilities are "critical" to BES reliability are wrong and go beyond the FERC directive. There is no technical basis for including flowgates as an appropriate measure of an item that is critical to reliability. A flowgate is a point of market congestion that may or may not have an important reliability impact. Because a "flowgate" may not have a reliability impact any larger than any other transmission line, Appendix B criterion B1 should be dropped. If the standard drafting team wishes to keep criteria B1 it should prove there is a sound and measureable method to show a flowgate is critical to the operation of the BES and the loss of such a facility would result in instability, uncontrolled separation, and cascading. 2) References to Planning Coordinators and Regional Entities in sections 4.2.2, 4.2.3, 4.2.6, R6, and Attachment B should be eliminated or replaced with Transmission Owner and Transmission Operators. Transmission Owners and Operators understand what facilities are critical to the operation of the BES and should determine what is and is not critical to the BES based upon FPA Section 215 criteria, IROLs, and TPL standards.
Response: Thank you for your comments. 1) Congestion and system reliability are not mutually exclusive concerns. The Interchange Distribution Calculator (IDC) was developed to address reliability concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. The IDC is intended to identify and unload critical circuits that could become overloaded due to transactions. While Flowgates and the IDC are used to manage congestion, the underlying basis for doing so is to preserve system reliability. The Flowgate Methodology defines that Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. If monitored Facilities of flowgates do not meet the Relay Loadability requirements in PRC-023, violation of physical system limitations could occur, leading to instability, uncontrolled separation, or cascading outages. As such, it is appropriate and necessary to include monitored Facilities of flowgates as				

applicable circuits under PRC-023-2. The drafting team acknowledges that Planning Coordinators do not decide which flowgates are included in the IDC; however, the NERC Functional Model does indicate that Planning Coordinators are responsible for coordinating transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators. Thus it is appropriate that Planning Coordinators, in applying the criteria in Appendix B, provide a screening as to whether the monitored Facilities of a flowgate are added to the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2. Based on a number of comments, the drafting team has modified criterion B1 to refer to "permanent" flowgates and has replaced the reference to "long-term reliability concerns" with "reliability concerns for loading of that circuit." The drafting team believes this more clearly reflects the intent to exclude flowgates that are established on a temporary basis and more clearly identifies the role of the Planning Coordinator in applying criterion B1. 2) The Planning Coordinator is the NERC Functional Model entity with the wide-area view and study expertise necessary to perform the assessment in Attachment B. The drafting team also notes that assigning this responsibility to the Planning Coordinator is consistent with the approved PRC-023-1 and FERC Order No. 733.				
Thomas C. Mielnik	MidAmerican Energy Co.	3	Negative	1) The Attachment B criteria for determining what circuits must follow PRC-023 criteria according to the FERC Order 733 and paragraph 69 specifying tests to determine what facilities are "critical" to BES reliability is wrong and goes beyond the FERC directive. There is no technical basis for including flowgates as an appropriate measure of an item that is critical to reliability. A flowgate is a point of market congestion that may or may not have a important reliability impact. Because a "flowgate" may not have a reliability impact any larger than any other transmission line, Appendix B criterion B1 should be dropped. If the standard drafting team wishes to keep criteria B1 it should prove that there is a sound and measureable method to prove that a flowgate is critical to the operation of the BES and the loss of such a facility would result in instability, uncontrolled separation, and cascading. 2) References to Planning Coordinators and Regional Entities in sections 4.2.2, 4.2.3, 4.2.6, R6, and Attachment B should be eliminated or replaced with Transmission Owner and Transmission Operators. These entities understand what facilities are critical to the operation of the BES and should determine what is and is not critical to the BES based upon FPA Section 215 criteria, IROLs, and TPL standards.
Response: Thank you for your comments. 1) Congestion and system reliability are not mutually exclusive concerns. The Interchange Distribution Calculator (IDC) was developed to address reliability concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. The IDC is intended to identify and unload critical circuits that could become overloaded due				

to transactions. While Flowgates and the IDC are used to manage congestion, the underlying basis for doing so is to preserve system reliability. The Flowgate Methodology defines that Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. If monitored Facilities of flowgates do not meet the Relay Loadability requirements in PRC-023, violation of physical system limitations could occur, leading to instability, uncontrolled separation, or cascading outages. As such, it is appropriate and necessary to include monitored Facilities of flowgates as applicable circuits under PRC-023-2. The drafting team acknowledges that Planning Coordinators do not decide which flowgates are included in the IDC; however, the NERC Functional Model does indicate that Planning Coordinators are responsible for coordinating transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators. Thus it is appropriate that Planning Coordinators, in applying the criteria in Appendix B, provide a screening as to whether the monitored Facilities of a flowgate are added to the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2. Based on a number of comments, the drafting team has modified criterion B1 to refer to "permanent" flowgates and has replaced the reference to "long-term reliability concerns" with "reliability concerns for loading of that circuit." The drafting team believes this more clearly reflects the intent to exclude flowgates that are established on a temporary basis and more clearly identifies the role of the Planning Coordinator in applying criterion B1.

2) The Planning Coordinator is the NERC Functional Model entity with the wide-area view and study expertise necessary to perform the assessment in Attachment B. The drafting team also notes that assigning this responsibility to the Planning Coordinator is consistent with the approved PRC-023-1 and FERC Order No. 733.

Christopher Schneider	MidAmerican Energy Co.	5	Negative	1) The Attachment B criteria for determining what circuits must follow PRC-023 criteria according to the FERC Order 733 and paragraph 69 specifying tests to determine what facilities are "critical" to BES reliability is wrong and goes beyond the FERC directive. There is no technical basis for including flowgates as an appropriate measure of an item that is critical to reliability. A flowgate is a point of market congestion that may or may not have a important reliability impact. Because a "flowgate" may not have a reliability impact any larger than any other transmission line, Appendix B criterion B1 should be dropped. If the standard drafting team wishes to keep criteria B1 it should prove that there is a sound and measureable method to prove that a flowgate is critical to the operation of the BES and the loss of such a facility would result in instability, uncontrolled separation, and cascading. 2) References to Planning Coordinators and Regional Entities in sections 4.2.2, 4.2.3, 4.2.6, R6, and Attachment B should be eliminated or replaced with Transmission Owner and Transmission Operators. These entities understand what facilities are critical to the operation of the BES and should determine what is and is not critical to the BES based upon FPA Section 215 criteria, IROLs, and TPL standards.

Response: Thank you for your comments.

1) Congestion and system reliability are not mutually exclusive concerns. The Interchange Distribution Calculator (IDC) was developed to address reliability concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. The IDC is intended to identify and unload critical circuits that could become overloaded due

to transactions. While Flowgates and the IDC are used to manage congestion, the underlying basis for doing so is to preserve system reliability. The Flowgate Methodology defines that Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. If monitored Facilities of flowgates do not meet the Relay Loadability requirements in PRC-023, violation of physical system limitations could occur, leading to instability, uncontrolled separation, or cascading outages. As such, it is appropriate and necessary to include monitored Facilities of flowgates as applicable circuits under PRC-023-2. The drafting team acknowledges that Planning Coordinators do not decide which flowgates are included in the IDC; however, the NERC Functional Model does indicate that Planning Coordinators are responsible for coordinating transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators. Thus it is appropriate that Planning Coordinators, in applying the criteria in Appendix B, provide a screening as to whether the monitored Facilities of a flowgate are added to the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2. Based on a number of comments, the drafting team has modified criterion B1 to refer to “permanent” flowgates and has replaced the reference to “long-term reliability concerns” with “reliability concerns for loading of that circuit.” The drafting team believes this more clearly reflects the intent to exclude flowgates that are established on a temporary basis and more clearly identifies the role of the Planning Coordinator in applying criterion B1.

2) The Planning Coordinator is the NERC Functional Model entity with the wide-area view and study expertise necessary to perform the assessment in Attachment B. The drafting team also notes that assigning this responsibility to the Planning Coordinator is consistent with the approved PRC-023-1 and FERC Order No. 733.

Jason L Marshall	Midwest ISO, Inc.	2	Negative	1. While we appreciate the drafting team’s effort to refine the flowgate criteria from the last posting, the modifications do not go far enough and still do not reflect the use of flowgates. NERC’s definition of flowgate includes two components. Let’s focus on the first component which represents those flowgates defined in the IDC. Because IDC flowgates list is updated monthly and the IDC users can add temporary flowgates to the IDC at any time, this is an inappropriate list to use. We appreciate the drafting team’s attempt to resolve this issue by including the caveat “that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator.” However, this really only confuses the matter and does not solve it. Reliability Coordinators add flowgates to manage real-time congestion. Planning Coordinators do not. Per the NERC functional model, they do not even have a role in deciding which flowgates to add to the IDC. Flowgates are added to the IDC to mitigate existing, known congestion points not congestion points identified in a long-term planning study that may never materialize due to changing conditions. Thus, IDC flowgates should be specifically excluded. Now let us focus on the second component of flowgate. The second component is much like the first component in that is it a mathematical construct to analyze the impact of power flows on the BES except is not required to be included in the IDC. There is nothing in the definition of a flowgate to give credence that is represents anything more than point to calculate power flows and the impact of transactions. Flowgates are primarily used to manage congestion on the system and to

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

				sell transmission system. Because it is convenient to select a group of lines as a proxy to sell transmission service or manage congestion does not mean that those group of lines represent a reliability issue. Thus, we do not believe any flowgates should be included in the list. Any true reliability issues can be identified through the TPL studies and those facilities that do not meet the performance requirements are what should be used. 2. We do not support criterion B4. It exceeds what is required in the TPL standards and what is required per the reliability directive in Order 729. The TPL standards allow system operator intervention for category C3 contingencies between the two independent Category B contingencies. This standard should not exceed those requirements in the TPL standards. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test “must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning.” Paragraph 80 states that “the test must be consistent with the general reliability principles embedded in the existing series of TPL” standards. Thus, exceeding the TPL standards could be argued as deviating from the directive. In response to comments that did not support this criterion during the first posting, the standards drafting team responded with “Testing multiple element contingencies while accounting for system adjustments between each element outage will not yield any facilities to be subject to PRC-023 as long as TPL-003 system performance requirements are met.” We think the drafting team missed a basic point about the standard. The issue is not whether the registered entity develops and documents corrective action plans TPL-003-0a R2 and R3. The issue is if the system as currently designed meets the performance requirements in TPL-003-0a R1 which allows for operator interventions on Category C3 contingencies. For those C3 contingencies that don’t currently meet the performance obligations after operator interventions, the subject facilities would be included PRC-023-2 R6 list of facilities. 3. We do not believe this requirement R4 is needed. Limiting a relay setting to 115% of the associated transmission line’s highest seasonal 15 minute rating does not equate to a line that will trip before the operator has time to intervene. It does not mean the line will trip in 15 minutes. In fact, the operator should be taking action well in advance of reaching a 15 minute limit and the operator is likely only using the 15 minute rating in extreme circumstances.

				4. Furthermore, PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings including those limited by relays. As a result, neither PRC-023-2 R3 nor R4 is even needed. We assume the drafting team must be aware of these FAC standard requirements because they did not even require reporting to the Reliability Coordinator, Planning Coordinator and Transmission Operator of those circuits that are actually limited by the relay per criterion 12. We agree that FAC-008-1 and FAC-009-1 collectively establish the necessary requirements to compel the Transmission Owner and Generator Owner to communicate these relay limited circuits and that no additional requirements are necessary.

Response: Thank you for your comments.

1. Congestion and system reliability are not mutually exclusive concerns. The Interchange Distribution Calculator (IDC) was developed to address reliability concerns. Markets are constrained to ensure that the transmission system is operated within physical system constraints that if violated, could lead to instability, uncontrolled separation, or cascading. The IDC is intended to identify and unload critical circuits that could become overloaded due to transactions. While Flowgates and the IDC are used to manage congestion, the underlying basis for doing so is to preserve system reliability. The Flowgate Methodology defines that Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. If monitored Facilities of flowgates do not meet the Relay Loadability requirements in PRC-023, violation of physical system limitations could occur, leading to instability, uncontrolled separation, or cascading outages. As such, it is appropriate and necessary to include monitored Facilities of flowgates as applicable circuits under PRC-023-2. The drafting team acknowledges that Planning Coordinators do not decide which flowgates are included in the IDC; however, the NERC Functional Model does indicate that Planning Coordinators are responsible for coordinating transfer capability (generally one year and beyond) with Transmission Planners, Reliability Coordinator, Transmission Owner, Transmission Operator, Transmission Service Provider, and neighboring Planning Coordinators. Thus it is appropriate that Planning Coordinators, in applying the criteria in Appendix B, provide a screening as to whether the monitored Facilities of a flowgate are added to the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2. Based on a number of comments, the drafting team has modified criterion B1 to refer to "permanent" flowgates and has replaced the reference to "long-term reliability concerns" with "reliability concerns for loading of that circuit." The drafting team believes this more clearly reflects the intent to exclude flowgates that are established on a temporary basis and more clearly identifies the role of the Planning Coordinator in applying criterion B1. FERC Order 733 has directed that this requirement be explicitly addressed within the requirements of PRC-023-2. FAC-008 and FAC-009 do not address this issue. FAC-009 requires transmitting the Facility Rating, whereas PRC-023-2 requires notification when the relay loadability is based on a 15-minute rating.

2. The drafting team received several comments regarding "going beyond" TPL requirements by not simulating manual system adjustment in between contingencies. The purpose of this criterion is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a

screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. As such, criterion B4 does not require that all double contingency combinations be tested. It also does not require that the loadings respect the published applicable ratings of the circuits. It does require that engineering judgment be used to select certain combinations of line outages to be studied without manual system adjustment to ensure that, if the manual adjustments were not completed before the second contingency, the relay settings on the lines remaining in service would not inappropriately trip the lines. 3. Providing this information to the specified entities addresses the potential for confusion as to the amount of time available to take corrective action. 4. FAC-008 and FAC-009 do not address this issue. FAC-009 requires transmitting the Facility Rating, whereas PRC-023-2 requires notification when the relay loadability is based on a 15-minute rating.				
Richard Burt	Minnkota Power Coop. Inc.	1	Negative	See comments submitted by MRO NSRS.
Response: Thank you for your comments. Please see the responses to comments submitted by MRO NSRS.				
Saurabh Saksena	National Grid	1	Negative	1. As per Section 4.2.3 (also included as bullet point 2 of Applicable circuits in Attachment B) "Transmission Lines operated below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry and the Planning Coordinator has determined are required to comply with this standard." National Grid believes that voltage levels less than 100 kV are outside NERC's jurisdiction and hence, requirements related to sub 100 kV levels should not be part of NERC standards. 2. National Grid recommends a provision in the standard which allows entities an option to 1. Either comply with standard for all applicable elements or 2. Apply the methodology as stated in Attachment B. The rationale is that entities that choose to comply with PRC-023 for all applicable elements should be recognized and should be exempted from complying with the methodology in Attachment B. 3. Requirement R6 of the proposed standard requires entities to apply criteria in Attachment B and conduct assessments with no more than 15 months between assessments to determine which transmission elements must comply with this standard. TPL standard which is considered to be the primary standard dealing with designing and planning of the system allows an interim assessment to rely on previous years simulations and does not mandate a stringent 15 month period between assessments. National Grid believes that an auxiliary PRC-023 standard should not present more stringent requirements than the primary TPL standard and recommends to remove the

<table>
<tr><td></td><td></td><td></td><td></td><td>"15 month between assessments" requirement.

4. National Grid seeks clarification on whether criterion 10 requires transformer to have load responsive protection to protection from mechanical damage. The wording in criterion 10 should be changed to “set transformer fault protection relay or transmission line relay on transmission line terminated with only a transformer.” For example, is this criteria requiring that a transformer with only differential protection and no other load responsive remote protection be mitigated with additional load responsive protection?</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.

1) The drafting team understands the concern with including facilities operated below 100 kV; however, the NERC Statement of Compliance Registry Criteria does allow Regional Entities the ability to identify such facilities operated below 100 kV as required to comply with NERC Reliability Standards. The drafting team has replaced the phrase “critical for the purposes of the Compliance Registry” with text from the ¶60 of Order No. 733, which references text in section III.d.2 of the NERC Statement of Compliance Registry Criteria, so the second category of circuits to be evaluated now refers to transmission lines and transformers operated below 100 kV “that are included on a critical facilities list defined by the Regional Entity.” The drafting team made corresponding modifications to the Applicability section.
2) The drafting team has added a new criterion B6 to include any circuit mutually agreed upon for inclusion by the Planning Coordinator and the Facility owner. Any circuit identified by criterion B6 would not require application of the other criteria in Attachment B.
3) The drafting team intended that an assessment be performed each year, but that the power flow analyses used to support the assessment need not be performed unless material changes to the system have occurred since the last assessment. The drafting team has added a footnote to criterion B4 to clarify this intent.
4) The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with Criterion 10 if it does exist. The standard has been modified to clarify this point.</td></tr>
<tr><td>Randy MacDonald</td><td>New Brunswick Power Transmission Corporation</td><td>1</td><td>Negative</td><td>Criteria 10 under Requirement 1. The Criteria could subject the industry to adding phase overcurrent protection to a large number of transformers. Clarification is needed</td></tr>
<tr><td>Alden Briggs</td><td>New Brunswick System Operator</td><td>2</td><td>Negative</td><td>Criteria 10 under Requirement 1. The Criteria could subject the industry to unnecessarily adding phase overcurrent protection to a large number of transformers. Clarification is required.</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.
The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point.</td></tr>
<tr><td>Gregory Campoli</td><td>New York Independent</td><td>2</td><td>Negative</td><td>comments provided</td></tr>
</table>

	System Operator			
Response: Thank you for your comments. Please refer to the drafting team responses in the Consideration of Comments document.				
Gerald Mannarino	New York Power Authority	5	Negative	Comments to Question 1: ---------------------- 1. Clarification is needed on whether criterion 10 requires a transformer to have load responsive protection to protect from mechanical damage, either from internal faults, or through faults. If load responsive protection for the transformer element does not presently exist, i.e. only differential protection exists for the transformer element, will load responsive transformer protection have to be added to comply with this criterion? 2. The wording in criterion 10 should be changed to “Set transformer fault protection relays or transmission line relays on transmission lines terminated only with a transformer to …….” 3. Is this criteria requiring that a transformer with only differential protection and no other load responsive remote protection be supplemented with additional load responsive protection? 4. The loading on phase angle regulators, and series reactors should be considered and mentioned. 5. Also, there appears to be words missing in criterion 9 of R1: “the maximum current flow from the ? to the ? under any system configuration.” From the NERC Webinar on 11/23/10 the intention was to address the possible locations where phase protection for the transformer could exist and not imply that this protection was needed at both locations. Comments to Question 8: ---------------------- 6. B2. Item B2 adds significant confusion to the process. The long term planning horizon may include transmission projects which have not even been built or alternative system configurations which do not exist, making it impossible for affected parties to set their relays appropriately. Suggested replacement language to avoid this issue: “Each circuit that is a monitored element of an IROL, assuming that all transmission elements are in service and the system is under normal conditions.” 7. B3. This item indicates that the circuits to be considered are to be agreed to by the plant owner and the Transmission Entity. Attachment B is applicable to the Planning Coordinator. If this item is by agreement by the plant and the

				Transmission Entity it should be removed from Attachment B and placed elsewhere in the document. If this is intended to apply to the Planning Coordinator, Transmission Entity should be replaced with Planning Coordinator. Why does B3 only apply to Nuclear Power Plants? 8. B4. This criterion is overly stringent and should be deleted. The system is neither planned nor operated to allow for two overlapping outages without operator action in between. If this criterion is retained, it should be made consistent with the requirements of TPL-003 where operator actions can be assumed between the first and second contingencies. Since a similar comment was made previously, more information is being provided following. 1. Since the system is neither planned nor operated to two overlapping outages in between, such testing may result in unsolved cases, or voltages well below criteria. In the case of an unsolved case, there are no flows to evaluate, making this standard impossible to apply. In the case of a solved case with voltages well below criteria, currents are likely to be incredibly high and therefore viewed as unrealistic. These concerns may limit the contingency selection to those which are not severe, eliminating any perceived benefit from this testing. 2. There is no guidance provided on how the system should be dispatched in the model upon which the overlapping contingencies are tested. This will result in significant discrepancies between the base assumptions used by the various Planning Coordinators. The contents of this standard should be reviewed to reflect the new definition of the Bulk Electric System.

Response: Thank you for your comments.

1) The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point.
2) The drafting team has considered this comment and similar comments and has modified the text of the standard as appropriate.
3) The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point.
4) The drafting team believes that the phase angle regulating transformers are already included in the standard in Criteria 10 and 11, and that series reactors are already included as part of the element in which they are inserted. This comment will be considered as we prepare future versions of the standard.
5) The text of the standard has been corrected.
6) In response to several comments on this subject the drafting team has replaced the reference to “determined in the long-term planning horizon” with “determined in the planning horizon pursuant to FAC-010.”

7) This criterion applies to the Planning Coordinator and requires that the Planning Coordinator include circuits that form a path “(as agreed to by the plant owner and the transmission entity) to supply off-site power to a nuclear plant as established in the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001” on the list of circuits for which Transmission Owners, Generator Owners, and Distribution Providers must comply with PRC-023-2. This criterion applies specifically to nuclear plants for the purpose of supporting nuclear plant safe operation and shutdown. The drafting team believes the added reference to the Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001 better reflects this intent. 8) The drafting team received several comments regarding “going beyond” TPL requirements by not simulating manual system adjustment in between contingencies. The purpose of this criterion is not to assess whether the system performance meets the TPL standard; rather, it is to be used as a screen to determine whether relays must be set to meet loadability requirements such that the circuits will not be tripped prematurely, resulting in widening of the initiating outage. As such, criterion B4 does not require that all double contingency combinations be tested. It also does not require that the loadings respect the published applicable ratings of the circuits. It does require that engineering judgment be used to select certain combinations of line outages to be studied without manual system adjustment to ensure that, if the manual adjustments were not completed before the second contingency, the relay settings on the lines remaining in service would not inappropriately trip the lines.				
Guy V. Zito	Northeast Power Coordinating Council, Inc.	10	Negative	Question has arisen during a technical evaluation of the NPCC membership regarding Criteria 10 under Requirement 1 of the draft standard. Would this requirement necessitate adding phase overcurrent protection to all transformers? Clarification is required for this Criteria before NPCC can support this standard so as to identify the implications of the adoption of such a requirement.
Response: Thank you for your comments. The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point.				
David H. Boguslawski	Northeast Utilities	1	Negative	Further clarification is needed for criterion 10 in R1. 1. Is it the intention of this criterion that all applicable transformers must have load responsive protection to prevent mechanical damage from a through fault? If load responsive protection for the transformer element does not presently exist, i.e. only differential protection exists for the transformer element, will load responsive transformer protection have to be added to comply with this criterion? 2. It is also suggested that R1 Criterion 10 wording be changed to “Set transformer fault protection relays or transmission line relays on transmission lines terminated only with a transformer to …….” since it appears from the NERC Webinar on 11/23/10 that the intention was address the possible locations where phase protection for the transformer could exist and not infer that this protection was needed at both locations.
Response: Thank you for your comments. 1. The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point.				

<table>
<tr><td colspan="5">2. The drafting team has considered this comment and similar comments and has modified the text of the standard as appropriate.</td></tr>
<tr><td>Joseph O'Brien</td><td>Northern Indiana Public Service Co.</td><td>6</td><td>Negative</td><td>See submitted comment form under "Posted for Comment"</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.

Please refer to the drafting team responses in the Consideration of Comments document.</td></tr>
<tr><td>Michelle DAntuono</td><td>Occidental Chemical</td><td>5</td><td>Negative</td><td>1. Further clarification is needed for criterion 10 in R1. Is it the intention of this criterion that all applicable transformers must have load responsive protection to prevent mechanical damage from a through fault? If load responsive protection for the transformer element does not presently exist, i.e. only differential protection exists for the transformer element, will load responsive transformer protection have to be added to comply with this criterion?
2. It is also suggested that R1 Criterion 10 wording be changed to “Set transformer fault protection relays or transmission line relays on transmission lines terminated only with a transformer to …….” since it appears from the NERC Webinar on 11/23/10 that the intention was address the possible locations where phase protection for the transformer could exist and not infer that this protection was needed at both locations.</td></tr>
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1. The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point.
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<tr><td>Douglas Hohlbaugh</td><td>Ohio Edison Company</td><td>4</td><td>Negative</td><td>Please see FirstEnergy's comments submitted separately through the comment period posting</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.

Please refer to the drafting team responses in the Consideration of Comments document.</td></tr>
<tr><td>Chifong L. Thomas</td><td>Pacific Gas and Electric Company</td><td>1</td><td>Negative</td><td>1. R2 is not clear. Is the requirement that OSB elements should not prevent the relay from tripping for a fault during overloaded conditions?

2. R6 does not include circuits or facilities that may have been deemed critical facilities for CIP purposes.

3. R7 timeframe to comply is 24 months. We are not sure that this is sufficient time to</td></tr>
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4. There is no stated requirement for periodic review, except for the Planning Coordinator. Does this imply an annual review and documentation for all facilities that are in scope of this standard?</td></tr>
<tr><td colspan="5">Response: Thank you for your comments.
1. This is exactly what the requirement is. The drafting team notes that Requirement R2 does not add a new obligation on Transmission Owners, Generator Owners, and Distribution Providers; it only explicitly states in PRC-023-2 an obligation that presently is included in Attachment A, section 2 of PRC-023-1.
2. Again, correct. The methodology and criteria are different between CIP and this standard. The criteria in Attachment B were selected to identify circuits that present a risk of cascading outages if relay loadability requirements are not met, consistent with the reliability objective of this standard.
3. The drafting team has considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1.
4. As with all standards, entities are expected to be in compliance all the time. Specification of a periodic review for the Transmission Owner, Generator Owner, and Distribution Provider seems unnecessary; they must naturally perform whatever reviews are necessary to assure continued compliance.</td></tr>
<tr><td>Richard J. Padilla</td><td>Pacific Gas and Electric Company</td><td>5</td><td>Negative</td><td>1. R2 is not clear to me. Is the requirement that OSB elements should not prevent the relay from tripping for a fault during overloaded conditions?
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1. This is exactly what the requirement is. The drafting team notes that Requirement R2 does not add a new obligation on Transmission Owners, Generator Owners, and Distribution Providers; it only explicitly states in PRC-023-2 an obligation that presently is included in Attachment A, section 2 of PRC-023-1.
2. Again, correct. The methodology and criteria are different between CIP and this standard. The criteria in Attachment B were selected to identify circuits that present a risk of cascading outages if relay loadability requirements are not met, consistent with the reliability objective of this standard.
3. The drafting team has considered a number of comments regarding the implementation timeframe and has extended the implementation time frame to 39 months to provide the Facility owners time to budget, procure, and install any protection system equipment modifications and for consistency with PRC-023-1.
4. As with all standards, entities are expected to be in compliance all the time. Specification of a periodic review for the Transmission Owner, Generator</td></tr>
</table>

Owner, and Distribution Provider seems unnecessary; they must naturally perform whatever reviews are necessary to assure continued compliance.				
Colt Norrish	PacifiCorp	1	Negative	1. PacifiCorp agrees with what it understands are the general concepts contained in Applicability Section 4.2, Requirements R6 and R7, and Attachment B of the proposed PRC-023-2. Namely, that: 1) the standard applies to all facilities (defined in Attachment A) above 200 kV and some facilities below 200 kV; 2) the Planning Coordinator is responsible for identifying the 100 â€“ 200 KV facilities (defined in Attachment A) to which the standard will apply (based on Attachment B); 3) some combination of the Regional Entity and the Planning Coordinator are responsible for identifying below 100 kV facilities (defined in Attachment A) to which the standard will apply (based on Attachment B); and 4) Transmission Owners, Generator Owners, and Distribution Providers that own the facilities that have been deemed applicable are responsible for complying with the requirements of the standard. If PacifiCorp's understanding of these concepts is generally correct, they must be more clearly stated in PRC-023-2. 2. As is currently drafted, the language contained in the applicability section, Requirements R6 and R7, and Attachment B are circular, unclear, and redundant. In order for registered entities to understand their obligations, the standards must be absolutely clear on what is required and by whom. PacifiCorp suggests the following: 1) remove R6 because it is redundant with the Applicability Section 4.2 (or vice versa) and clarify the role of the Planning Coordinator and the application of Attachment B criteria; 2) Applicability Section 4.2.3 and the second bullet in Attachment B appear to contradict as Section 4.2.3 defines a role for the Planning Coordinator whereas the second bullet in Attachment B does not -this may be correct for some reason, however, the role of the Planning Coordinator and the Regional Entity in evaluating facilities below 100 kV must be more clearly defined. PacifiCorp does not have any substantive issues with the Attachment B criteria. However, in order to be enforceable, the legal obligations imposed on registered entities under PRC-023-2 must be more clearly stated.
John Apperson	PacifiCorp	3		
Sandra L. Shaffer	PacifiCorp	5		
Scott L Smith	PacifiCorp	6		
Response: Thank you for your comments. 1. Extensive revisions were made to Attachment B and throughout the standard to improve clarity. The drafting team believes that these responsibilities are now clearly defined. 2. The drafting team has removed parts 6.1 and 6.2 from Requirement R6 to avoid redundancy, and has revised the Applicability section and Attachment B based on industry comments to provide clarity. The drafting also has deleted Requirement R7 and modified the Effective Dates section to address the timeframe in which Facility owners must comply with Requirements R1 through R5 when the Planning Coordinator identifies a circuit for which the Facility owner must comply with the standard.				
Anthony E Jablonski	ReliabilityFirst Corporation	10	Affirmative	ReliabilityFirst votes affirmative but offers the following comments. 1.Within the Applicability there are references to PRC-023 –but the version number is missing.

				2.R1 should be broken down into two separate requirements. The first requiring the applicable entities to use one of the criteria. The second requiring the applicable entity to evaluate relay loadability at 0.85 per unit voltage and a power factor angle of 30 degrees. This will make the VSL designations cleaner.
Response: Thank you for your comments. 1) The drafting team has revised the standard as you suggest. 2) The drafting team believes that this comment addresses approved content in PRC-023-1, and is therefore outside the scope of this project.				
John C. Allen	Rochester Gas and Electric Corp.	1	Negative	Criteria 10 under Requirement 1 could subject the industry to adding phase overcurrent protection to a large number of transformers. Clarification is needed as to the implications of this requirement.
Response: Thank you for your comments. The standard does not require that load responsive protection be present to protect for internal faults or through faults. The standard does require that the protection be set in accordance with criterion 10 if it does exist. The standard has been modified to clarify this point				
Rich Salgo	Sierra Pacific Power Co.	1	Negative	We cast a negative ballot because the Standard as written, contemplates a fairly complicated planning study process (Attachment B), to determine which facilities can be included/excluded from compliance with the relay loadability standard itself. This was done for good intent, and was a compromise between the industry's position of 200kV and above applicability, and FERC's general position to apply this Standard to everything above 100kV. However, now we have a recent FERC Order on the definition of BES (Order 743). This Order compels NERC to develop a new BES definition that is 100kV-based, yet allows for exclusion criteria that NERC is to develop. As such, this should supersede the criteria proposed in Attachment B. Continuing with Appendix B as written will cause the unintended consequence of having conflicts between the ultimate BES list and the list of PRC-023-applicable facilities. It seems they should be the same.
Response: Thank you for your comments. All circuits that are necessary for operating the interconnected transmission network are not necessarily important for the purposes of PRC-023. The criteria in Attachment B were selected to identify circuits that present a risk of cascading outages if relay loadability requirements are not met, consistent with the reliability objective of this standard. Thus, it is expected that the list of circuits identified by applying the criteria in Attachment B will be a subset of the Bulk Electric System. This standard like all others will need to be reviewed when the new definition of the Bulk Electric System is approved.				

Long T Duong	Snohomish County PUD No. 1	1	Affirmative	The District believes to be an unintended consequence – a Catch-22 – from the interaction of the revised CIP-002-4 Attachment 1's Criteria 1.4 (Blackstart Resources) and 1.5 (identified Cranking Paths) with the control center size and facility exceptions in 1.15, 1.16 and 1.17. This interaction will cause many if not all registered TOPs, BAs and Generation Owners that control Blackstart Resources used in a TOP restoration plan to become subject to CIP-002 through CIP-009, regardless of entity size. EOP-005 requires all TOPs to have a restoration plan. The District's reading of EOP-005 indicates that each TOP must identify one or more Blackstart Resources. CIP-002-4 Criterion 1.4 requires a TOP to identify each such Blackstart Resource identified in its restoration plan as a critical asset. Criterion 1.5 requires the identification of certain Cranking Paths as critical assets. Criterion 1.15 requires that each generation control center or backup control center used to control a Blackstart Resource identified under Criterion 1.4 be identified as a critical asset, without any exception for generation control center size (1500 MW). Criterion 1.16 requires each transmission control center or backup control center used to control a Cranking Path identified under Criterion 1.5 be identified as a critical asset, without any exception for TOP control center size. Criterion 1.17 requires each Balancing Authority control center or backup control center used to control a Blackstart Resource identified under Criterion 1.4 be identified as a critical asset, without any exception for Balancing Authority control center size (1500 MW). In effect, Criterion 1.4 swallows all exceptions created under 1.15 through 1.17, with the possible exception of a generation-only BA that does not have any Blackstart Resource obligations to its TOP. All vertically integrated utilities would be responsible for CIP-002 through CIP-009, including small BAs and TOPs that do not own any other Critical Assets. To address this problem, we propose the following edits to 1.4 and 1.5 shown in redline CAPS/strikeout: 1.4. Each Blackstart Resource identified in the RESTORATION PLAN FOR A Transmission Operator's restoration plan SERVING LOAD OR GENERATION EQUAL TO OR GREATER THAN AN AGGREGATE OF 1500 MW IN A SINGLE INTERCONNECTION. 1.5. The Facilities comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource(S) IDENTIFIED IN 1.4. to the first interconnection point of the generation unit(s) to be started, or up to the point on the Cranking Path where two or more path options exist, as identified in the Transmission Operator's restoration plan. This surgical approach ensures that generation, TOP and BA control centers with responsibility for other critical generation and transmission assets are still responsible for full CIP-002-4 through CIP-009 compliance. However, small BA/TOP systems with no initial obligations to the RC

				and larger TOPs for regional restoration would not be deemed "critical." The experience of these smaller systems is that their restoration obligations have not been relied upon to restore the BES, but rather to start generation to serve local load after a system separation – and then to wait for direction from the RC on resynchronization with the rest of the BES, once voltage and frequency are stabilized. While we recognize that cyber events may have an impact on the availability of resources, the fundamental fact is the vast majority of Blackstart Resources and control centers will be protected under CIP-002 through -009, because they will be classified as Critical/High Impact under the proposed criteria, as revised above. Thus the revised criteria support rather than undermine the distinction between categorization of big iron/big aluminum resources and their associated control centers as Critical or High Impact in the development of CIP-002-4. The categorization and development of security controls for smaller resources as either medium or low impact for the BES, should be addressed through development of additional bright line criteria and associated security controls in the next phase of this project (CIP-002-5 or CIP-010/011.)
Response: Thank you for your comments. The drafting team notes that the criteria in Attachment B are intentionally different than the CIP requirements for identifying critical facilities. It appears that the comments submitted would be more appropriately submitted to the Project 2008-06 — Cyber Security — Order 706 drafting team.				
Charles H Yeung	Southwest Power Pool	2	Negative	SPP supports the comments submitted by the ISO RTO Council Standards Review Committee which raise many concerns on the requirements proposed.
Response: Thank you for your comments. Please see our response to the comments submitted by the ISO RTO Council Standards Review Committee.				
Travis Metcalfe	Tacoma Public Utilities	3	Negative	1. Transmission or Transformers that normally would not be considered BES assets are subject to inclusion by the Planning Coordinator. The criteria for inclusion have not been developed yet. 2. Attachment A Section 1.6 was added due to FERC Order 733, but it is still vague what includes "Supervisory Elements". Please clarify supervisory elements (Does it include RTUs?) 3. Detailed direction about relay setting methodology could be expanded to 110-kV level by this revision. Much more research should be devoted to such detailed changes to evaluate impact to other protection and operation constraints, before such settings are mandatory.

				4. The new requirement (R2) may present conflicting choices for a relay engineer, since out-of-step blocking is technically challenging to set, sense and discriminate from certain loading and fault conditions.

Response: Thank you for your comments.

1. The NERC Statement of Compliance Registry Criteria permits application of NERC Reliability Standards to certain facilities operated below 100 kV, such as for transmission elements operated below 100 kV that are included on a critical facilities list defined by the Regional Entity. The test by which the Regional Entity may make this determination is outside the scope of this standard. The criteria by which the Planning Coordinators determine for which of the circuits on the list the applicable entities must comply with the standard are defined in Attachment B.
2. Attachment A, Section 1.6 has been modified to include supervisory elements only as they apply to current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications. The drafting team believes this modification provides clarity that this section does not apply to RTUs and other applications.
3. The drafting team understands your concern and will place this item in the issues database for future consideration in the next general revision of the standard. However, the drafting team notes that PRC-023-1 already applies to lines operated at 100 kV to 200 kV and the drafting team does not believe that a significant number of sub-100 kV circuits will be impacted. As such, the drafting team disagrees that more research is required prior to implementing PRC-023-2.
4. The drafting team notes that Requirement R2 does not add a new obligation on Transmission Owners, Generator Owners, and Distribution Providers; it only explicitly states in PRC-023-2 an obligation that presently is included in Attachment A, Section 2 of PRC-023-1.

Keith Morisette	Tacoma Public Utilities	4	Negative	Tacoma Power is submitting a Negative vote due to the following concerns: · 1. Transmission or Transformers that normally would not be considered BES assets are subject to inclusion by the Planning Coordinator. The criteria for inclusion have not been developed yet. 2. Attachment A Section 1.6 was added due to FERC Order 733, but it is still vague what includes “Supervisory Elements”. Please clarify supervisory elements (Does it include RTUs?) 3. Detailed direction about relay setting methodology could be expanded to 110-kV level by this revision. Much more research should be devoted to such detailed changes to evaluate impact to other protection and operation constraints, before such settings are mandatory.

				4. The new requirement (R2) may present conflicting choices for a relay engineer, since out-of-step blocking is technically challenging to set, sense and discriminate from certain loading and fault conditions. Thank you for consideration of these concerns.

Response: Thank you for your comments.

1. The NERC Statement of Compliance Registry Criteria permits application of NERC Reliability Standards to certain facilities operated below 100 kV, such as for transmission elements operated below 100 kV that are included on a critical facilities list defined by the Regional Entity. The test by which the Regional Entity may make this determination is outside the scope of this standard. The criteria by which the Planning Coordinators determine for which of the circuits on the list the applicable entities must comply with the standard are defined in Attachment B.
2. Attachment A, Section 1.6 has been modified to include supervisory elements only as they apply to current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications. The drafting team believes this modification provides clarity that this section does not apply to RTUs and other applications.
3. The drafting team understands your concern and will place this item in the issues database for future consideration in the next general revision of the standard. However, the drafting team notes that PRC-023-1 already applies to lines operated at 100 kV to 200 kV and the drafting team does not believe that a significant number of sub-100 kV circuits will be impacted. As such, the drafting team disagrees that more research is required prior to implementing PRC-023-2.
4. The drafting team notes that Requirement R2 does not add a new obligation on Transmission Owners, Generator Owners, and Distribution Providers; it only explicitly states in PRC-023-2 an obligation that presently is included in Attachment A, Section 2 of PRC-023-1.

Michael C Hill	Tacoma Public Utilities	6	Negative	1. Transmission or Transformers that normally would not be considered BES assets are subject to inclusion by the Planning Coordinator. The criteria for inclusion have not been developed yet. 2. Attachment A Section 1.6 was added due to FERC Order 733, but it is still vague what includes “Supervisory Elements”. Please clarify supervisory elements (Does it include RTUs?) 3. Detailed direction about relay setting methodology could be expanded to 110-kV level by this revision. Much more research should be devoted to such detailed changes to evaluate impact to other protection and operation constraints, before such settings are mandatory.

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<tr><td colspan="5">Response: Thank you for your comments.
1. The NERC Statement of Compliance Registry Criteria permits application of NERC Reliability Standards to certain facilities operated below 100 kV, such as for transmission elements operated below 100 kV that are included on a critical facilities list defined by the Regional Entity. The test by which the Regional Entity may make this determination is outside the scope of this standard. The criteria by which the Planning Coordinators determine for which of the circuits on the list the applicable entities must comply with the standard are defined in Attachment B.
2. Attachment A, Section 1.6 has been modified to include supervisory elements only as they apply to current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications. The drafting team believes this modification provides clarity that this section does not apply to RTUs and other applications.
3. The drafting team understands your concern and will place this item in the issues database for future consideration in the next general revision of the standard. However, the drafting team notes that PRC-023-1 already applies to lines operated at 100 kV to 200 kV and the drafting team does not believe that a significant number of sub-100 kV circuits will be impacted. As such, the drafting team disagrees that more research is required prior to implementing PRC-023-2.
4. The drafting team notes that Requirement R2 does not add a new obligation on Transmission Owners, Generator Owners, and Distribution Providers; it only explicitly states in PRC-023-2 an obligation that presently is included in Attachment A, Section 2 of PRC-023-1.</td></tr>
<tr><td>Larry D. Grimm</td><td>Texas Reliability Entity</td><td>10</td><td>Negative</td><td>1. In R1, criterion 9 is missing some words at the end. We think it is supposed to say “. . . from the load to the system under any system configuration.”

2. In R1, criterion 12(c), it appears that the reference should be changed from “criterion 12” to “criterion 12(b)”.

3. In Attachment B, criterion B1, “Texas Interconnection” should be changed to “ERCOT Interconnection.” That is the correct name of this Interconnection. (FYI, the ERCOT Interconnection does not include several parts of the Texas BES, which are in WECC, SPP, and SERC.)

4. In R1, criteria 1, 4, and 10, the draft specifies that Facility Ratings are to be “expressed in amperes.” In our experience these ratings are ordinarily expressed in MVA. In criteria 11, a rating is referenced, but the units are not specified. We suggest</td></tr>
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				either (a) not specifying units for these ratings in the standard, or (b) specifying “MVA” rather than “amperes.” 5. In R1, criteria 10 and 11, the references to “operator established emergency transformer rating” should be changed to “owner established emergency transformer rating.” Note that FAC-008 and FAC-009 call on the Transmission Owner and Generator Owner entities to establish Facility Ratings. 6. In R5, why is the Regional Entity designated to receive a list of facilities with relays set according to criterion 12? Texas RE does not ordinarily act as a clearinghouse for this kind of information. If the intention is to share this information with other entities, this list should be provided to the Reliability Coordinator or some other appropriate functional entity, rather than to the Regional Entity. 7. In Attachment B, criterion B3, “plant owner” should be changed to “Generator Owner” and “Transmission Entity” should be changed to “Transmission Owner,” in order to clearly designate the responsible entities. 8. In Attachment B, criterion B4, the reference to “power flow analysis” should be changed to “power flow assessment,” in order to make it consistent with the term used in R6. 9. In Attachment B, criterion B4, the second bullet is unclear as written. We suggest changing it to read as follows: “For circuits operated between 100 kV and 200 kV, evaluate the post-contingency loading against the Facility Rating after contingency evaluations per TPL-003, Category A, B, and C3 with the near-term load flow case.”

Response: Thank you for your comments

1. The text has been corrected.
2. The drafting team believes that this comment addresses approved content in PRC-023-1, and is therefore outside the scope of this project. The drafting team will place this item in the issues database for future consideration in the next general revision of the standard.
3. In response to other comments, Attachment B, criterion B1 has been revised to delete the reference to the Texas Interconnection.
4. The drafting team believes that this comment addresses existing content in PRC-023-1, and is therefore outside the scope of this project.
5. The drafting team believes that this comment addresses existing content in PRC-023-1, and is therefore outside the scope of this project.
6. The Regional Entity (RE), via the delegation agreements, is a part of the ERO; thus, by submitting the information to the RE, the ERO will have the information available to respond to requests from users, owners, and operators of the BES.
7. This criterion references Nuclear Plant Interface Requirements (NPIRs) pursuant to NUC-001, and therefore refers to entities consistent with the

description in NUC-001 which does not refer to NERC Functional Model entities. 8. The drafting team notes that the power flow analysis required in criterion B4 is one aspect of the assessment identified in Requirement R6. Criterion B4 therefore is not inconsistent with Requirement R6. 9. A number of changes have been made to criterion B4 in response to industry comments. While the drafting team has not incorporated this suggestion, we believe the modifications to the criterion provide clarity desired by the commenter.				
Keith V. Carman	Tri-State G & T Association, Inc.	1	Negative	Reference Tri-State Generation & Transmission Assn., Inc. comments submitted to NERC via the Project 2010-13 Formal Comment link.
Janelle Marriott	Tri-State G & T Association, Inc.	3	Negative	Reference Tri-State Generation and Transmission Assn., Inc. Formal comments submitted to NERC electronically via the Project 2010-13 Formal Comment link. Thank you.
Response: Thank you for your comments. Please refer to the drafting team responses in the Consideration of Comments document.				
Jonathan Appelbaum	United Illuminating Co.	1	Negative	The drafting team should include a criteria for Phase Angle Regulators and Series reactors. These are types of transformers and for clarity purposes should be called out specifically.
Response: Thank you for your comments. The drafting team believes that the phase angle regulating transformers are already included in the standard in Criteria 10 and 11, and that series reactors are already included as part of the element in which they are inserted. This comment will be considered as we prepare future versions of the standard.				
Allen Klassen	Westar Energy	1	Affirmative	Please define the term "mechanical withstand" used in B.R1.10.
Response: Thank you for your comments. The mechanical withstand is defined is IEEE C57.109-1993, *IEEE Guide for Liquid-Immersed Transformer Through-Fault-Current Duration* and a reference to this standard has been added as a footnote to address your concerns.				
Brandy A Dunn	Western Area Power Administration	1	Negative	1. The different wording regarding applicability to transmission lines between 100-kV and 200-kV is confusing as it is not clear from these statements whether or not the Planning Coordinator makes this determination. Under “Applicability”, 4.2.2 states: Transmission lines operated at 100 kV to 200 kV that the Planning Coordinator has determined are required to comply with this standard. Attachment B indicates applicable circuits are: Transmission lines operated at 100 kV to 200 kV [….]. 2. Similarly the different wording regarding applicability to transformers having low voltage terminals between 100-kV and 200-kV is confusing as it is not clear from these statements whether or not the Planning Coordinator makes this determination. Under “Applicability”, 4.2.5 states: Transformers with low voltage terminals connected at 100 kV to 200 kV that the Planning Coordinator has determined are required to comply with this standard. Attachment B indicates applicable circuits are: [….] transformers with low voltage terminals connected at 100 kV to 200 kV

				3. Regarding the former comments 1 and 2, Attachment B could reference 4.2.1 - 4.2.6, or repeat them exactly, unless there is another intent of describing applicability again under Attachment B. 4. In “B. Requirements R1.”: suggest the following mod from: “power factor angle of 30 degrees.” to: “power factor angle of 30 degrees, where the power factor angle is material to the operation of the relay such as with mho type characteristics.” 5. 6.1 and 6.2 are further re-statements of applicability criteria. It would be less confusing to have these appear one place in the document and reference them elsewhere, or repeat them identically each time they are used. 6. Attachment A - The meaning of 1.6 and its relationship to the second bullet under 2.1 is unclear and confusing.
Response: Thank you for your comments. 1. The drafting team has divided the Applicability section to differentiate between circuits subject to Requirement R6 (the circuits to which the Planning Coordinator must apply Attachment B) and the circuits subject to Requirements R1 through R5 (the circuits identified by the Planning Coordinator through the Application of Attachment B). The drafting team believes this change addresses the commenter’s concern. 2. The drafting believes the changes to the Applicability section address this concern also. 3. The drafting team has modified Attachment B to use the same description as the circuits subject to Requirement R6 in the Applicability section. 4. The drafting team believes that this comment addresses existing content in PRC-023-1, and is therefore outside the scope of this project. 5. 1) The drafting team has eliminated parts 6.1 and 6.2 from Requirement R6. The drafting team understands that repeating this information in Requirement R6 and in Attachment B is redundant and potentially confusing. In addition, the drafting team has revised the text in Attachment B to more clearly convey the intent. 6. The drafting team has modified believes that this relationship is clear. Section 1.6 specifically includes supervisory elements associated with current-based, communication-assisted schemes where the scheme is capable of tripping for loss of communications, and 2.1 (second bullet) excludes all elements only enabled during a loss of communication, with the exception of supervisory elements included in Section 1.6				
Forrest Brock	Western Farmers Electric Coop.	1	Affirmative	WFEC recognizes the work of the SDT in composing a draft standard for relay loadability that displays the team's effort to keep the requirements within the standard focused on achieving reliability for the BES.
Response: Thank you for your comment.				
Gregory L Pieper	Xcel Energy, Inc.	1	Negative	Sections 4.2.3 and 4.2.6, in the applicability section, are of concern to us because they include facilities that would not otherwise be part of the Bulk Electric System (i.e. facilities operating less than 100 kV). Other drafting teams have contemplated including generating units connected at
Michael Ibold	Xcel Energy, Inc.	3		

Liam Noailles	Xcel Energy, Inc.	5		less than 100 kV, and have been advised that if they did that, Generator Owners that were not Registered Entities with NERC would have to register and would be required to comply with ALL Generator Owner requirements in ALL of the NERC standards. This same risk exists under the currently proposed PRC-023-2. We suggest that a requirement be added to require the PA to notify the unregistered entity, if their facility has been determined to be critical. In addition, there should be additional time permitted for those entities to get into compliance and that should be reflected in the implementation plan.
David F. Lemmons	Xcel Energy, Inc.	6		

Response: Thank you for your comments.

The drafting team understands the concern with including facilities operated below 100 kV; however, the NERC Statement of Compliance Registry Criteria does allow Regional Entities the ability to identify such facilities operated below 100 kV as required to comply with NERC Reliability Standards. The drafting team has replaced the phrase “critical for the purposes of the Compliance Registry” with text from the ¶60 of Order No. 733, which references text in section III.d.2 of the NERC Statement of Compliance Registry Criteria, so the second category of circuits to be evaluated now refers to transmission lines and transformers operated below 100 kV “that are included on a critical facilities list defined by the Regional Entity.” The drafting team made corresponding modifications to the Applicability section.