Individual or group. (38 Responses)
Name (25 Responses)
Organization (25 Responses)
Group Name (13 Responses)
Lead Contact (13 Responses)
Question 1 (35 Responses)
Question 1 Comments (38 Responses)
Question 2 (33 Responses)
Question 2 Comments (38 Responses)
Question 3 (37 Responses)
Question 3 Comments (38 Responses)
Question 4 (37 Responses)
Question 4 Comments (38 Responses)
Question 5 (35 Responses)
Question 5 Comments (38 Responses)
Question 6 (37 Responses)
Question 6 Comments (38 Responses)
Question 7 (35 Responses)
Question 7 Comments (38 Responses)
Question 8 (36 Responses)
Question 8 Comments (38 Responses)

-
Individual
Joe Petaski
Manitoba Hydro
Yes
Yes
Yes
Yes
No
1. We don’t think that the system would change that fast to warrant the additional work of conducting an assessment every year. The entities involved have 24 months to make the necessary changes as given in R7. If an annual assessment is required then this should be added as a requirement to TPL-001-2 rather than buried in PRC-023. It would be more efficient to perform an assessment over the 10-year planning horizon every 2-3 years. Critical facilities identified in the assessment can be monitored in the in-between years to ensure construction schedules are on track and the need is still there. One initial detailed assessment of the current year facilities could be done but then the assessment should be more focused on additions and changes. 2. The VSLs for R6 are too severe. The system doesn’t change that rapidly and getting the list to the entities involved before 60 days does not impact reliability given that they have 2 years to comply with changes.
No
The effective date should not be a uniform date, it should be dependent on the number of circuits that have been identified and determined as critical circuits for an individual utility.
No
Effectively, there is no substantial difference between the protection elements described in section 1.6 and the protection elements described on second bullet in Section 2.1. Why should the protection elements in section 1.6 be included? During loss of communication, the supervisory elements associated with current based, communication-assisted schemes (such as line current differential scheme and phase comparison scheme) may be the only protection elements to provide high speed protection which may be necessary from system reliability perspective. As a result, these supervisory elements should be set low enough to ensure that they can detect all fault condition. Since these supervisory elements are only in effect under loss of communication contingency, I don’t think they should be subjected to the same requirements as those load responsive elements under normal condition. They should be treated the same as those elements described on the first bullet in section 2.1.
No
In attachment B and the standard, there’s discussion of 15 min., up to 4 hour, 4-8 hour and more than 8 hour ratings. This is very prescriptive and doesn’t match the requirements in the Facility rating methodology standard or the model building limitations. It seems there is a disconnect between the FAC, TPL and PRC standards.
Group
Electric Market Policy

Mike Garton
Yes
Yes
Yes
Yes
Yes
Yes
Yes
5.1 Requirement R1. Dominion would like to see the exception of "switch on to fault" schemes added back in.
Individual
Mace Hunter
Lakeland Electric
Yes
Yes
Yes
Yes
No
In R6.2 the phrase “for the purposes of the Compliance Registry and” is used. The same phrase is also used under Applicability in sections 4.2.3 and 4.2.6. What is the purpose of this phrase in these sections? I do not think that the phrase has any value in these locations. The phrase is also used in the PRC-023 – Attachment B in the second bullet under “Criteria”. It seems to imply that if a circuit is identified as a critical facility that fact could be used to drive registration of an entity that otherwise may not require registration. If that is the intent then I would suggest modifying the phrase in the attachment to “that may require entity registration in the Compliance Registry “
Yes
Yes
Yes
Group
Potomac Holdings Inc & Affiliates
David K Thorne
Yes
Please note that a typographical error exists in Requirement R1 Criterion 9. The sentence should end with the phrase “flow from the load to the system under any system configuration”. The words load and system have been inadvertently omitted in both this draft and the previous draft.
Yes
Yes
In the SDT’s response “Consideration of Comments on Revisions to Relay Loadability for Order 733 SAR and an initial set of proposed requirements – Project 2010-13” dated November 1, 2010, the SDT proposed to establish the effective date for requirements R4 & R5 as “the first day of the first calendar quarter following 24 months after regulatory approvals.” However in the latest draft of the standard the 24 month requirement was replaced with 6 months. Which is correct?
Yes
In the SDT’s response “Consideration of Comments on Revisions to Relay Loadability for Order 733 SAR and an initial set of proposed requirements – Project 2010-13” dated November 1, 2010, the SDT proposed to establish the effective date for requirements R4 & R5 as “the first day of the first calendar quarter following 24 months after regulatory approvals.” However in the latest draft of the standard the 24 month requirement was replaced with 6 months. Which is correct?
Yes

Yes
No
The current wording of section 1.6 is a significant improvement over the previous version. The intent of this section was to specifically address phase overcurrent supervising elements (i.e. phase fault detectors) associated with pilot wire, phase comparison, and line current differential schemes where the scheme is capable of tripping for loss of communications. However, we believe that the term “current-based communication-assisted schemes” is too generic and may be confusing without mention of the specific schemes to which this requirement applies. Also, only phase overcurrent supervising elements are in scope, not ground overcurrent supervising elements. Therefore, to clarify the requirement we suggest replacing the current wording with either “Phase overcurrent supervisory elements (i.e. phase fault detectors) associated with pilot wire, phase comparison, and line current differential schemes, where the scheme is capable of tripping for loss of communications” or “Phase overcurrent supervisory elements (i.e. phase fault detectors) associated with current-based communication-assisted schemes (i.e. pilot wire, phase comparison, and line current differential) where the scheme is capable of tripping for loss of communications”.
Yes
Individual
Joe O'Brien for Tom Nappi
NIPSCO
No
The mechanical withstand is not an appropriate value because every fault event will reduce the life of a transformer. Setting the limit at the maximum expected one time event limit will prematurely destroy the transformers. Maybe a sliding scale would be better with each transfromer owner to decided how much expected life to risk for faults.
No
We believe this is already included
No
We're not sure what the value is in this requirement?
No
We believe the R1 criterion 12 is needed- but the reporting requirment is not.
No
Only the owner or TO GO DP should apply the criteria – which can be then reported to the PC
No
We believe only the owners of facilities should have this requirment, not the PC
No
Don’t know what is referred to here except maybe a current differential scheme. There is no need for this added requirement.
Yes
The method seems OK but the standard requirement R1 should be changed because lower voltage lines have far more resistance and arc resistance needs to be included. General Comments: We think that the proposed revised standard incorrectly assigns responsibility to the PC instead of the TO,GO DP Also, the new standard forces compliance on lower voltage lines which would limit protection of equipment which will ultimately lead to many fewer networked lines and a less reliable electric system.
Individual
Nicholas Klemm
Western Area Power Administration
No
Established industry standards and practices have defined the mechanical damage portion of the transformer curve to apply for repetitive faults. Neither FERC nor NERC should have the right to contradict established technical practices. Entities should be able to coordination protection systems taking into account protection and controls (e.g. the use of lockouts) which prevent repetitive exposure to mechanical damage thereby alleviating cumulative effects. Also, it is not clear what "transmission line relays on transmission lines terminated only with a transformer..." applies to. Need clarification.
Yes
Yes
Yes
No
Feel that NERC is delving too much into the technical details. Should allow Planning Coordinators to establish their own study methodologies.
Yes

No
Both the FERC order and section 1.6 are unclear.
No
Is this necessary? Allow Planning Coordinators to do their jobs and decide which circuits are important.
Individual
Richard Burt
Minnkota Power Cooperative, Inc.
Yes
Yes
Yes
Yes
No
Many facilities with voltages between 100kV and 200kV will only impact a well-defined local load region if they trip. There is no risk of cascading outages beyond the local load region. The criteria in Attachment B should allow these types of facilites to be dismissed from evaluation.
Yes
Yes
No
Many facilities with voltages between 100 kV and 200 kV will only impact a well-defined local load region if they trip. There is no risk of cascading outages beyond the local load region. The criteria in Attachment B should allow these facilities to be dismissed from further evaluation.
Group
Northeast Power Coordinating Council
Guy Zito
No
Clarification is needed on whether criterion 10 requires a transformer to have load responsive protection to protect from mechanical damage, either from internal faults, or through faults. If load responsive protection for the transformer element does not presently exist, i.e. only differential protection exists for the transformer element, will load responsive transformer protection have to be added to comply with this criterion? The wording in criterion 10 should be changed to “Set transformer fault protection relays or transmission line relays on transmission lines terminated only with a transformer to …….” Is this criteria requiring that a transformer with only differential protection and no other load responsive remote protection be supplemented additional load responsive protection? The loading on phase angle regulators, and series reactors should be considered and mentioned. Also, there appears to be words missing in criterion 9 of R1: “the maximum current flow from the ? to the ? under any system configuration.” From the NERC Webinar on 11/23/10 the intention was to address the possible locations where phase protection for the transformer could exist and not imply that this protection was needed at both locations.
Yes
Yes
Yes
Yes
Yes
Yes
No
B2. Item B2 adds significant confusion to the process. The long term planning horizon may include transmission projects which have not even been built or alternative system configurations which do not exist, making it impossible for affected parties to set their relays appropriately. Suggested replacement language to avoid this issue: “Each circuit that is a monitored element of an IROL, assuming that all transmission elements are in service and the system is under normal conditions.” B3. This item indicates that the circuits to be considered are to be agreed to by the plant owner and the Transmission Entity. Attachment B is applicable to the Planning Coordinator. If this item is by agreement by the plant and the Transmission Entity it should be removed from Attachment B and placed elsewhere in the document. If this is intended to apply to the Planning Coordinator, Transmission Entity should be replaced with Planning Coordinator. Why does B3

only apply to Nuclear Power Plants? B4. This criterion is overly stringent and should be deleted. The system is neither planned nor operated to allow for two overlapping outages without operator action in between. If this criterion is retained, it should be made consistent with the requirements of TPL-003 where operator actions can be assumed between the first and second contingencies. Since a similar comment was made previously, more information is being provided following. 1. Since the system is neither planned nor operated to two overlapping outages in between, such testing may result in unsolved cases, or voltages well below criteria. In the case of an unsolved case, there are no flows to evaluate, making this standard impossible to apply. In the case of a solved case with voltages well below criteria, currents are likely to be incredibly high and therefore viewed as unrealistic. These concerns may limit the contingency selection to those which are not severe, eliminating any perceived benefit from this testing. 2. There is no guidance provided on how the system should be dispatched in the model upon which the overlapping contingencies are tested. This will result in significant discrepancies between the base assumptions used by the various Planning Coordinators. The contents of this standard should be reviewed to reflect the new definition of the Bulk Electric System.
Individual
Kathleen Goodman
ISO New England Inc.
No
B2. Item B2 adds significant confusion to the process. The long term planning horizon may include transmission projects which have not even been built or alternative system configurations which do not exist, making it impossible for affected parties to set their relays appropriately. Suggested replacement language to avoid this issue: “Each circuit that is a monitored element of an IROL, assuming that all transmission elements are in service and the system is under normal conditions.” B3. This item indicates that the circuits to be considered are to be agreed to by the plant owner and the Transmission Entity. Attachment B is applicable to the Planning Coordinator. If this item is by agreement by the plant and the Transmission Entity it should be removed from Attachment B and placed elsewhere in the document. If this is intended to apply to the Planning Coordinator, Transmission Entity should be replaced with Planning Coordinator. B4. This criterion is overly stringent and should be deleted. The system is neither planned nor operated to allow for two overlapping outages without operator action in between. If this criterion is retained, it should be made consistent with the requirements of TPL-003 where operator actions can be assumed between the first and second contingencies. Since a similar comment was made previously, more information is being provided in this set of comments. 1. Since the system is neither planned nor operated to two overlapping outages in between, such testing may result in unsolved cases, or voltages well below criteria. In the case of an unsolved case, there are no flows to evaluate, making this standard impossible to apply. In the case of a solved case with voltages well below criteria, currents are likely to be incredibly high and therefore viewed as unrealistic. These concerns may limit the contingency selection to those which are not severe, eliminating any perceived benefit from this testing. 2. There is no guidance provided on how the system should be dispatched in the model upon which the overlapping contingencies are tested. This will result in significant discrepancies between the base assumptions used by the various Planning Coordinators.
Group
Pacific Northwest Small Public Power Utility Comment Group
Steve Alexanderson
No
The comment group finds R1.10 very confusing when attempting to understand it in the context of IEEE C57.109-1993. C57.109 identifies a solid curve as the thermal damage curve, while a dotted dog leg is the mechanical damage curve. Generally the dog leg is only considered for those class II and III transformers subjected to frequent through faults and all class IV transformers. Is the intent of the SDT to require this level of protection for all transformers regardless of through fault frequency and/or transformer class? If the SDT really meant to protect transformers from thermal or combination damage, please note that it is not possible to completely protect transformers from the thermal damage of low current long duration faults while still complying with the 150% of maximum rating. The thermal damage curve extends down to twice the base current. A footnote in C57.109 states that base current is established from the lowest nameplate kVA rating. A typical transformer with two stages of cooling will have a high nameplate rating of 1.67 times this base rating. The first bullet of R1.10 states affected entities must allow 1.5 times the maximum, so we are up to 2.5 times the base rating. Since we must allow this much without tripping, the relay must be set even higher. 1.2 times would be a secure margin, so the relay is set to pickup at 3 times the base rating. This setting would of course violate the first part of R1 criterion 10 because the transformer’s fault capability would be exceeded for faults between 2 and 3 times the base rating. We also note that criterion 11 is apparently an exception to criterion 10, but this is not altogether clear since 10 is for fault protection while 11 is for overload protection. Please rewrite this (these) criterion (criteria) to clarify the SDT’s intent(s).
Yes
Yes
No
The FERC Order 773 page 224 states that this information is to be made available to the entities “by request.” Unless a request happens to coincide with the annual submittal, this order is not being addressed. There is also no requirement that

the Regional Entity make the lists available to the other entities as ordered. We don’t believe the intent of the order was achieved in R5.
Yes
Yes
Yes
No
We thank the SDT for addressing our concern regarding radially operated circuits. We note, however, that the key word “operated” from the consideration of comments was dropped before it reached the standard. Please change the last bullet of B4 to: "Radially operated circuits serving only load are excluded."
Individual
Greg Rowland
Duke Energy
Yes
Yes
Yes
Yes
No
• R6.1 and R6.2 unnecessarily duplicate the first part of Attachment B, and should be deleted from R6. • R6.3 and R6.4 are both associated with maintaining the list and should be combined into a separate requirement (new R7), with its own VRF and VSLs. Including the year for a facility should apply to all the criteria, not just B4. Suggested wording for new R7: “Maintain a list of circuits that must comply with this standard due to meeting Attachment B criteria. For each circuit, include the applicable criteria and the year studied for which the criteria first applies, when a facility is added to the list.” • R6.5 should become a new R8 with its own VRF and VSLs. No wording changes needed.
No
Since the Attachment B criteria are applied beyond the operating horizon, R7 should be rewritten (and also renumbered as R9). Suggested wording: “ Each Transmission Owner, Generator Owner, and Distribution Provider shall implement Requirement R1, Requirement R2, Requirement R3, Requirement R4, and Requirement R5 for each facility that is added to the Planning Coordinator’s list of facilities that must comply with this standard pursuant to Requirement R6, by the first day of the first calendar quarter of the year in which Attachment B criteria first apply. [Violation Risk Factor: High] [Time Horizon: Long Term Planning]
Yes
No
• B2 needs additional clarification, because identification could be in the short term or long term planning horizon. Suggested rewording: “B2. Each circuit that is a monitored Element of an IROL where the IROL was determined beyond the operating horizon.” • B3 needs additional clarification, to explicitly identify the necessary agreement between the plant owner and Transmission Entity. Suggested rewording: “Each circuit that forms a path (as agreed to by the plant owner and the Transmission Entity pursuant to NUC-001) to supply off-site power to nuclear plants.
Individual
Tim Hinken
Kansas City Power & Light
Yes
Yes
No
We do not believe this requirement is needed. Limiting a relay setting to 115% of the associated transmission line’s highest seasonal 15 minute rating does not equate to a line that will trip before the operator has time to intervene. It does not mean the line will trip in 15 minutes. In fact, the operator should be taking action well in advance of reaching a 15 minute limit and the operator is likely only using the 15 minute rating in extreme circumstances. Furthermore, PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings including those limited by relays. As a result, neither PRC-023-2 R3 nor R4 is even needed. We assume the drafting team must be aware of these FAC standard requirements because they did not even require reporting to the Reliability

Coordinator, Planning Coordinator and Transmission Operator of those circuits that are actually limited by the relay per criterion 12. We agree that FAC-008-1 and FAC-009-1 collectively establish the necessary requirements to compel the Transmission Owner and Generator Owner to communicate these relay limited circuits and that no additional requirements are necessary.
No
While we don’t necessarily have an issue with the equipment owner communicating these relay limited circuits to the Regional Entities, we don’t believe this is needed for reliability and therefore it should not be included in the reliability standard. Given that it is unclear what the information will even be used for, if it will be needed long-term, and that it is likely will not change much, if at all, from year to year, we believe a data request through NERC’s Rules of Procedure section 1600 would be more appropriate. In that way, we don’t have to modify the standard later when NERC and the Regions determine they don’t need the data annually.
No
It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV that are part of the Bulk Electric System. This information is not readily available and there is no requirement for the Regional Entity to communicate it to them. Thus, inaction by the auditor (i.e. Regional Entity) could actually cause the Planning Coordinator to violate this requirement. This is clearly a conflict of interest. Why does the Planning Coordinator need to identify which circuits are identified per criteria B4? There is no justification given for this need and there is nothing else that appears to require action as a result of this information. Thus, it is purely administrative and should be removed. Registered entities should never be subject to potential sanctions for violations of purely administrative portions of requirements. Why does the Planning Coordinator need to provide this information to the Reliability Coordinator? There is nothing for the Reliability Coordinator to do with the information. The Reliability Coordinator only needs to be informed if equipment becomes derated and then that should occur through the normal communication of ratings per FAC-009-1.
No
We do not believe that R7 is needed. The applicability section of the standard is clear that the standard applies to those circuits identified in R6. This requirement could be construed as potential for double jeopardy because failure to comply with Requirements 1-5 for represent a violation of both Requirement 7 and Requirement 1-5.
Yes
No
While we appreciate the drafting team’s effort to refine the flowgate criteria from the last posting, the modifications do not go far enough and still do not reflect the use of flowgates. NERC’s definition of flowgate includes two components. Let’s focus on the first component which represents those flowgates defined in the IDC. Because IDC flowgates list is updated monthly and the IDC users can add temporary flowgates to the IDC at any time, this is an inappropriate list to use. We appreciate the drafting team’s attempt to resolve this issue by including the caveat “that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator.” However, this really only confuses the matter and does not solve it. Reliability Coordinators add flowgates to manage real-time congestion. Planning Coordinators do not. Per the NERC functional model, they do not even have a role in deciding which flowgates to add to the IDC. Flowgates are added to the IDC to mitigate existing, known congestion points not congestion points identified in a long-term planning study that may never materialize due to changing conditions. Thus, IDC flowgates should be specifically excluded. Now let us focus on the second component of flowgate. The second component is much like the first component in that is it a mathematical construct to analyze the impact of power flows on the BES except is not required to be included in the IDC. There is nothing in the definition of a flowgate to give credence that is represents anything more that point to calculate power flows and the impact of transactions. Flowgates are primarily used to manage congestion on the system and to sell transmission system. Because it is convenient to select a group of lines as a proxy to sell transmission service or manage congestion does not mean that those group of lines represent a reliability issue. Thus, we do not believe any flowgates should be included in the list. Any true reliability issues can be identified through the TPL studies and those facilities that do not meet the performance requirements are what should be used. We do not support criterion B4. It exceeds what is required in the TPL standards and what is required per the reliability directive in Order 729. The TPL standards allow system operator intervention for category C3 contingencies between the two independent Category B contingencies. This standard should not exceed those requirements in the TPL standards. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test “must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning.” Paragraph 80 states that “the test must be consistent with the general reliability principles embedded in the existing series of TPL” standards. Thus, exceeding the TPL standards could be argued as deviating from the directive. The directive is to be consistent not exceed. Exceeding the TPL standards is not consistency. In response to comments that did not support this criterion during the first posting, the standards drafting team responded with “Testing multiple element contingencies while accounting for system adjustments between each element outage will not yield any facilities to be subject to PRC-023 as long as TPL-003 system performance requirements are met.” We think the drafting team missed a basic point about the standard. The issue is not whether the registered entity develops and documents corrective actions actions plans TPL-003-0a R2 and R3. The issue is if the system as currently designed meets the performance requirements in TPL-003-0a R1 which allows for operator interventions on Category C3 contingencies. For those C3 contingencies that don’t currently meet the performance obligations after operator interventions, the subject facilities would be included PRC-023-2 R6 list of facilities.
Individual
Andrew Pusztai
American Transmission Company
Yes

Yes
Yes
Yes
Yes
Except ATC is recommending the following wording change for Requirement R 6.2 which provides clarification on the application of the criteria: “Apply the criteria to the following Elements in its Planning Coordinator Area, if any: those transmission lines operated below 100 kV and those transformers with low voltage terminal connections below 100 kV that the Regional Entity has identified as critical facilities for the purposes of the Compliance Registry.”
No
ATC believes it is difficult to determine without knowing the full scope of work. Until the Planning criteria can be determined, the scope is unknown. Assuming not many assets are added, two years would be a more reasonable amount of time.
Yes
Yes
Group
Tennessee Valley Authority
Joshua Wooten
Yes
Yes
Yes
Yes
No
Per Requirement R6 criterion 2, the Planning Coordinator is better suited to analyze the subsystem and its effect on the BES than the Regional Entity, so “Regional Entity” should be replaced with “Planning Coordinator”. Please also see Question 8 comment concerning the use of “flowgate” in Attachment B section B1.
Yes
Yes
No
The NERC Glossary defines a flowgate as: 1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System. The IDC flowgates change often thus making it difficult to coordinate those changes with the critical lines list provided by the Planning Coordinator in Attachment B section B1. We assume that No. 2 above is the definition that the SDT was referring. However, for clarity, we recommend that either the word “flowgate” be specifically defined in Attachment B or removed.
Individual
David Burke
Orange and Rockland Utilities, Inc.
No
Clarification is needed on whether criterion 10 requires a transformer to have load responsive protection to protect from mechanical damage. The wording in criterion 10 should be changed to “set transformer fault protection relay or transmission line relay on transmission line terminated with only a transformer.” Is this criteria requiring that a transformer with only differential protection and no other load responsive remote protection be mitigated with additional load responsive protection? The loading on phase angle regulators, and series reactors should also be considered and mentioned.
No
What is the expectation for verifying that the out-of-step blocking elements allow tripping of phase protection relays for faults that occur during the loading conditions used to verify transmission line relay loadability? It would be costly and time consuming to verify this. To comply with this requirement, utilities may have to remove OOS protections all together. This should be able to be tested during routine trip testing. Between the trip testing procedures, and relay calibrations this requirement should be satisfied, and easily documented.
Yes

Yes
Yes
Yes
Yes
No
Why does B3 only apply to Nuclear Power Plants only?
Group
Tri-State G & T System Protection
Bill Middaugh
No
There can be cases where the transformer withstand capability will be exceeded if 150% of the applicable maximum transformer rating is used for the pickup of overcurrent relays. The requirement cannot then be met if no transformer emergency rating is established. Modify to indicate that if the loading requirement violates the protection requirement, then the protection requirement should be used while allowing the maximum loading possible without violating the protection requirement.
Yes
No
We believe that the list of facilities with transmission line relays that use Requirement R1 criterion 2 needs to be given only to the Transmission Operators as directed by Paragraph 186 of FERC Order no. 733, and not also to the Planning Coordinators and Reliability Coordinators. We also believe that an initial submittal is sufficient until any responsible entity begins or stops using that criterion on any element. Periodic duplicate submittals are unnecessary and unique submittals would more easily identify the loadability issues that the operators need to consider. The FERC Order did not require annual submittals.
No
Paragraph 224 of FERC Order no. 733 requires that the ERO document and have available upon request the list of facilities that use this criterion. The proposed standard is not applicable to the Regional Entity so there is no method to require the RE to provide the data to the ERO. That seems to indicate that the data should be provided to the ERO rather than the Regional Entity. We also believe that an initial submittal is sufficient until any responsible entity begins or stops using that criterion on any element. Periodic duplicate submittals are unnecessary and unique submittals would more easily identify the loadability issues that the operators need to consider. The FERC Order did not require annual submittals.
Yes
Yes
Yes
Yes
While we agree that it is a technically sound approach, we have concerns that the criterion B4 is over-burdensome. Paragraph 82 of FERC Order 733 indicates that the existing TPL simulations and assessments should be a component of the test. By excluding manual intervention in the assessments the Attachment is expanding the scope beyond the Commission’s Order. We think there should be a test based on the existing assessments required by the TPL standards that would then trigger a subsequent test with no manual intervention. An example would be if an element’s loading exceeded 100% of its Facility Rating using the normal assessment, then the assessment with no manual intervention would be applied and subsequent steps of criterion B4 would be followed. We think that criterion B5 is too vague, may be discriminatory, is unnecessary, and should be removed. There is very little basis listed for this criterion above and beyond those listed in criterion B4, the criterion may be applied discriminatorily or differently even within the same interconnection, it potentially excludes the protection system owner from having input in the process, and there is no redress for appeal by the owner. It seems highly unlikely that elements that are not identified through criterion B4 will need to be included. If some form of criterion B5 is included in Attachment B, then it needs to better define a technical basis for the request for inclusion, a procedure to initiate the request for inclusion, due process defined for evaluation of the request, and inclusion of the protection system owner in the evaluation process and the agreement.
Individual
J. S. Stonecipher, PE
City of Jacksonville Beach, FL dba/Beaches Energy Services
Yes
However, R1 and R2 have binary VSLs, where they should be percentages of all relays that need to meet the standard based on statistical sampling.
Yes

R1 and R2 have binary VSLs, where they should be percentages of all relays that need to meet the standard based on statistical sampling. (See previous comment for R1.)
No
No, that is way too frequent. It should be a much longer time criteria, say 5 years, with a requirement that if there is a CHANGE, the information is sent to the PC, TO and RC.
No
No, once again, that is way too frequent and creates another unnecessary burden for record keeping. It should be a much longer time criteria, say 5 years, with a requirement that if there is a CHANGE, the information is sent to the PC, TO and RC.
Yes
Yes
Yes
Yes
Attachment B, the criterion in B4 seem rather arbitrary; but, the numbers seem reasonable.
Group
Midwest ISO Standards Collaborators
Jason Marshall
Yes
No
We do not believe this requirement is needed. Limiting a relay setting to 115% of the associated transmission line's highest seasonal 15 minute rating does not equate to a line that will trip before the operator has time to intervene. It does not mean the line will trip in 15 minutes. In fact, the operator should be taking action well in advance of reaching a 15 minute limit and the operator is likely only using the 15 minute rating in extreme circumstances. Furthermore, PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings including those limited by relays. As a result, neither PRC-023-2 R3 nor R4 is even needed. We assume the drafting team must be aware of these FAC standard requirements because they did not even require reporting to the Reliability Coordinator, Planning Coordinator and Transmission Operator of those circuits that are actually limited by the relay per criterion 12. We agree that FAC-008-1 and FAC-009-1 collectively establish the necessary requirements to compel the Transmission Owner and Generator Owner to communicate these relay limited circuits and that no additional requirements are necessary.
No
While we don't necessarily have an issue with the equipment owner communicating these relay limited circuits to the Regional Entities, we don't believe this is needed for reliability and therefore it should not be included in the reliability standard. Given that it is unclear what the information will even be used for, if it will be needed long-term, and that it is likely will not change much, if at all, from year to year, we believe a data request through NERC's Rules of Procedure section 1600 would be more appropriate. In that way, we don't have to modify the standard later when NERC and the Regions determine they don't need the data annually.
No
It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV that are part of the Bulk Electric System. This information is not readily available and there is no requirement for the Regional Entity to communicate it to them. Thus, inaction by the auditor (i.e. Regional Entity) could actually cause the Planning Coordinator to violate this requirement. This is clearly a conflict of interest. Why does the Planning Coordinator need to identify which circuits are identified per criteria B4? There is no justification given for this need and there is nothing else that appears to require action as a result of this information. Thus, it is purely administrative and should be removed. Registered entities should never be subject to potential sanctions for violations of purely administrative portions of requirements. Why does the Planning Coordinator need to provide this information to the Reliability Coordinator? There is nothing for the Reliability Coordinator to do with the information. The Reliability Coordinator only needs to be informed if equipment becomes derated and then that should occur through the normal communication of ratings per FAC-009-1.
No
We do not believe that R7 is needed. The applicability section of the standard is clear that the standard applies to those circuits identified in R6. This requirement could be construed as potential for double jeopardy because failure to comply with Requirements 1-5 would represent a violation of Requirement 7 also.
Yes
No
While we appreciate the drafting team's effort to refine the flowgate criteria from the last posting, the modifications do not

go far enough and still do not reflect the use of flowgates. NERC's definition of flowgate includes two components. Let's focus on the first component which represents those flowgates defined in the IDC. Because IDC flowgates list is updated monthly and the IDC users can add temporary flowgates to the IDC at any time, this is an inappropriate list to use. We appreciate the drafting team's attempt to resolve this issue by including the caveat "that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator." However, this really only confuses the matter and does not solve it. Reliability Coordinators add flowgates to manage real-time congestion. Planning Coordinators do not. Per the NERC functional model, they do not even have a role in deciding which flowgates to add to the IDC. Flowgates are added to the IDC to mitigate existing, known congestion points not congestion points identified in a long-term planning study that may never materialize due to changing conditions. Thus, IDC flowgates should be specifically excluded. Now let us focus on the second component of flowgate. The second component is much like the first component in that is it a mathematical construct to analyze the impact of power flows on the BES except is not required to be included in the IDC. There is nothing in the definition of a flowgate to give credence that is represents anything more than point to calculate power flows and the impact of transactions. Flowgates are primarily used to manage congestion on the system and to sell transmission system. Because it is convenient to select a group of lines as a proxy to sell transmission service or manage congestion does not mean that those group of lines represent a reliability issue. Thus, we do not believe any flowgates should be included in the list. Any true reliability issues can be identified through the TPL studies and those facilities that do not meet the performance requirements are what should be used. We do not support criterion B4. It exceeds what is required in the TPL standards and what is required per the reliability directive in Order 729. The TPL standards allow system operator intervention for category C3 contingencies between the two independent Category B contingencies. This standard should not exceed those requirements in the TPL standards. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test "must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning." Paragraph 80 states that "the test must be consistent with the general reliability principles embedded in the existing series of TPL" standards. Thus, exceeding the TPL standards could be argued as deviating from the directive. In response to comments that did not support this criterion during the first posting, the standards drafting team responded with "Testing multiple element contingencies while accounting for system adjustments between each element outage will not yield any facilities to be subject to PRC-023 as long as TPL-003 system performance requirements are met." We think the drafting team missed a basic point about the standard. The issue is not whether the registered entity develops and documents corrective action plans TPL-003-0a R2 and R3. The issue is if the system as currently designed meets the performance requirements in TPL-003-0a R1 which allows for operator interventions on Category C3 contingencies. For those C3 contingencies that don't currently meet the performance obligations after operator interventions, the subject facilities would be included PRC-023-2 R6 list of facilities.
Individual
Thad K. Ness
American Electric Power
No
American Electric Power sees two issues with R1's Criterion 10. First, transformer "mechanical withstand capability" is undefined, vague, and subject to various interpretations. The terminology used in this criterion must be more tightly defined to prevent ambiguity or else referenced to some agreed-upon standard such as IEEE C57.109-1993. Second, American Electric Power agrees that it is appropriate for the 150% and 115% settings criteria to apply to line relays terminated only with a transformer. However, Criterion 10 seems to assume that transmission line relays on transmission lines terminated with a transformer are also typically intended to protect the transformer. This is not normally or necessarily true. If the line relays are not intended to protect the transformer and as long as the transformer relaying properly protects the transformer from mechanical damage, there is no reason for Criterion 10 to apply to the line relays. To address these two deficiencies in Criterion 10, American Electric Power sets forth the following two-part replacement language for Criterion 10: 10.1 Set transformer fault protection relays such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability as defined by IEEE C57.109-1993 or its successor standard and so that the relays do not operate at or below the greater of: • 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment. • 115% of the highest operator established emergency transformer rating. 10.2 Set transmission line relays on transmission lines terminated only with a transformer so that the relays do not operate at or below the greater of: • 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment. • 115% of the highest operator established emergency transformer rating. If the transformer fault protection relays on the line-terminated transformer do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability, then the transmission line relays do not also need to provide the same protection against transformer mechanical damage.
Yes
Yes
Yes
No
The wording under Sections 4.2.3, 4.2.6, 6.2, and the applicability portion of Attachment B needs to be made consistent to avoid any misinterpretations and confusion. - Section 4.2.3 – Delete the portion that reads "... and the Planning Coordinator has determined are required to comply with this standard" for this section to read the same as the associated sentence under the applicability portion of Attachment B. - Section 4.2.6 – Same comment as Section 4.2.3 (above). - Section 6.2 – Reword to read: "Apply the criteria to transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV that the Regional Entity has identified as critical for the purposes of the

Compliance Registry."
No
Need to provide a 60-month timeline to implement the noted requirements for each facility that is added to the Planning Coordinator's initial list of facilities that must comply with this standard, versus the 24-month timeline to implement the noted requirements for each facility that is added to the Planning Coordinator's established list of facilities that must comply with this standard. This is a practical consideration that recognizes the high likelihood that the number of facilities that will be identified during development of the initial list of facilities will be many times greater than the incremental number of facilities that will be identified during the annual assessments and added to the established list of facilities. In addition, need to specify under this requirement whether any facilities that drop off the Planning Coordinator's list of facilities while still within the applicable (60-month or 24-month) implementation timeline must still comply with this standard.
No
The wording of Attachment A, section 1.6 needs to be made consistent to avoid any confusion. 1.6 Reword to read: "Supervisory elements used as fault detectors associated with pilot wire or current differential protection systems where the system is capable of tripping for loss of communications".
No
Include the following refinements to the criteria for determining the facilities that must comply with the standard: o Add new B5 that reads: "Each circuit that is operated below 100 kV that the Regional Entity has identified as critical for the purposes of the Compliance Registry." o Renumber B5 to B6. o Need to consider the amount of load that is placed at risk when determining whether the circuit must comply with the standard. The threshold should be set at the DOE reporting level of 300 MW. o Need to include a review and appeals process as part of the annual assessment for the Planning Coordinator to review the proposed facilities with the transmission entity prior to adding those facilities to the Planning Coordinator's list of facilities that must comply with the standard.
Individual
Steve Wadas
Nebraska Public Power District
Yes
Yes
No
NERC does not need a separate requirement for TOs, GOs, and DPs to specifically report R1, criterion 2. If they meet the requirement the line will not trip. If they meet the requirement and the line is overloaded the operator will receive an alarm and will take action within 15 minutes.
Yes
Yes
If attachment B is kept then the PC should determine which transmission elements must comply with the standard.
Yes
Yes
No
Attachment B, Criteria B1 could add at least 24 transmission elements which are transmission lines operated at 100kv to 200kv. After reviewing the MRO and SPP criteria these lines will not be included per PRC-023. Loss of any of these lines will not cause a cascading outage which PRC-023 is intended to prevent.
Group
MRO's NERC Standards Review Subcommittee
Carol Gerou
Yes
Yes
No
We do not believe this requirement is needed. Limiting a relay setting to 115% of the associated transmission line's highest seasonal 15 minute rating does not equate to a line that will trip before the operator has time to intervene. It does not mean the line will trip in 15 minutes. In fact, the operator should be taking action well in advance of reaching a 15 minute limit and the operator is likely only using the 15 minute rating in extreme circumstances. Furthermore, PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings including those limited by relays. As a result, neither PRC-023-2 R3 nor R4 is even needed. We assume the drafting team must be aware of these FAC standard requirements because they did not even require reporting to the Reliability

Coordinator, Planning Coordinator and Transmission Operator of those circuits that are actually limited by the relay per criterion 12. We agree that FAC-008-1 and FAC-009-1 collectively establish the necessary requirements to compel the Transmission Owner and Generator Owner to communicate these relay limited circuits and that no additional requirements are necessary.
No
While we don't necessarily have an issue with the equipment owner communicating these relay limited circuits to the Regional Entities, we don't believe this is needed for reliability and therefore it should not be included in the reliability standard. Given that it is unclear what the information will even be used for, if it will be needed long-term, and that it is likely will not change much, if at all, from year to year, we believe a data request through NERC's Rules of Procedure section 1600 would be more appropriate. In that way, we don't have to modify the standard later when NERC and the Regions determine they don't need the data annually.
No
It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV that are part of the Bulk Electric System. This information is not readily available and there is no requirement for the Regional Entity to communicate it to them. Thus, inaction by the auditor (i.e. Regional Entity) could actually cause the Planning Coordinator to violate this requirement. This is clearly a conflict of interest. Why does the Planning Coordinator need to identify which circuits are identified per criteria B4? There is no justification given for this need and there is nothing else that appears to require action as a result of this information. Thus, it is purely administrative and should be removed. Registered entities should never be subject to potential sanctions for violations of purely administrative portions of requirements. Why does the Planning Coordinator need to provide this information to the Reliability Coordinator? There is nothing for the Reliability Coordinator to do with the information. The Reliability Coordinator only needs to be informed if equipment becomes derated and then that should occur through the normal communication of ratings per FAC-009-1.
No
We do not believe that R7 is needed. The applicability section of the standard is clear that the standard applies to those circuits identified in R6. This requirement could be construed as potential for double jeopardy because failure to comply with Requirements 1 through 5 would represent a violation of both Requirement 7 and Requirements 1 through 5.
Yes
No
While we appreciate the drafting team's effort to refine the flowgate criteria from the last posting, the modifications do not go far enough and still do not reflect the use of flowgates. NERC's definition of flowgate includes two components. Let's focus on the first component which represents those flowgates defined in the IDC. Because IDC flowgates list is updated monthly and the IDC users can add temporary flowgates to the IDC at any time, this is an inappropriate list to use. We appreciate the drafting team's attempt to resolve this issue by including the caveat "that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator." However, this really only confuses the matter and does not solve it. Reliability Coordinators add flowgates to manage real-time congestion. Planning Coordinators do not. Per the NERC functional model, they do not even have a role in deciding which flowgates to add to the IDC. Flowgates are added to the IDC to mitigate existing, known congestion points not congestion points identified in a long-term planning study that may never materialize due to changing conditions. Thus, IDC flowgates should be specifically excluded. Now let us focus on the second component of flowgate. The second component is much like the first component in that is it a mathematical construct to analyze the impact of power flows on the BES except is not required to be included in the IDC. There is nothing in the definition of a flowgate to give credence that is represents anything more that point to calculate power flows and the impact of transactions. Flowgates are primarily used to manage congestion on the system and to sell transmission system. Because it is convenient to select a group of lines as a proxy to sell transmission service or manage congestion does not mean that those group of lines represent a reliability issue. Thus, we do not believe any flowgates should be included in the list. Any true reliability issues can be identified through the TPL studies and those facilities that do not meet the performance requirements are what should be used. We do not support criterion B4. It exceeds what is required in the TPL standards and what is required per the reliability directive in Order 729. The TPL standards allow system operator intervention for category C3 contingencies between the two independent Category B contingencies. This standard should not exceed those requirements in the TPL standards. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test "must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning." Paragraph 80 states that "the test must be consistent with the general reliability principles embedded in the existing series of TPL" standards. Thus, exceeding the TPL standards could be argued as deviating from the directive. In response to comments that did not support this criterion during the first posting, the standards drafting team responded with "Testing multiple element contingencies while accounting for system adjustments between each element outage will not yield any facilities to be subject to PRC-023 as long as TPL-003 system performance requirements are met." We think the drafting team missed a basic point about the standard. The issue is not whether the registered entity develops and documents corrective actions plans per TPL-003-0a R2 and R3. The issue is if the system as currently designed meets the performance requirements in TPL-003-0a R1 which allows for operator interventions on Category C3 contingencies. For those C3 contingencies that don't currently meet the performance obligations after operator interventions, the subject facilities would be included PRC-023-2 R6 list of facilities.
Individual
Joe Knight
Great River Energy
Yes
Yes

No
We do not believe this requirement is needed. Limiting a relay setting to 115% of the associated transmission line's highest seasonal 15 minute rating does not equate to a line that will trip before the operator has time to intervene. It does not mean the line will trip in 15 minutes. In fact, the operator should be taking action well in advance of reaching a 15 minute limit and the operator is likely only using the 15 minute rating in extreme circumstances. Furthermore, PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings including those limited by relays. As a result, neither PRC-023-2 R3 nor R4 is even needed. We assume the drafting team must be aware of these FAC standard requirements because they did not even require reporting to the Reliability Coordinator, Planning Coordinator and Transmission Operator of those circuits that are actually limited by the relay per criterion 12. We agree that FAC-008-1 and FAC-009-1 collectively establish the necessary requirements to compel the Transmission Owner and Generator Owner to communicate these relay limited circuits and that no additional requirements are necessary.
No
While we don't necessarily have an issue with the equipment owner communicating these relay limited circuits to the Regional Entities, we don't believe this is needed for reliability and therefore it should not be included in the reliability standard. Given that it is unclear what the information will even be used for, if it will be needed long-term, and that it is likely will not change much, if at all, from year to year, we believe a data request through NERC's Rules of Procedure section 1600 would be more appropriate. In that way, we don't have to modify the standard later when NERC and the Regions determine they don't need the data annually.
No
It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV and that are part of the Bulk Electric System. This information is not readily available and there is no requirement for the Regional Entity to communicate it to them. Thus, inaction by the auditor (i.e. Regional Entity) could actually cause the Planning Coordinator to violate this requirement. This is clearly a conflict of interest. Why does the Planning Coordinator need to identify which circuits are identified per criteria B4? There is no justification given for this need and there is nothing else that appears to require action as a result of this information. Thus, it is purely administrative and should be removed. Registered entities should never be subject to potential sanctions for violations of purely administrative portions of requirements. Why does the Planning Coordinator need to provide this information to the Reliability Coordinator? There is nothing for the Reliability Coordinator to do with the information. The Reliability Coordinator only needs to be informed if equipment becomes derated and then that should occur through the normal communication of ratings per FAC-009-1
No
We do not believe that R7 is needed. The applicability section of the standard is clear that the standard applies to those circuits identified in R6. This requirement could be construed as potential for double jeopardy because failure to comply with Requirements 1 through 5 would represent a violation of both Requirement 7 and Requirements 1 through 5.
Yes
No
While we appreciate the drafting team's effort to refine the flowgate criteria from the last posting, the modifications do not go far enough and still do not reflect the use of flowgates. NERC's definition of flowgate includes two components. Let's focus on the first component which represents those flowgates defined in the IDC. Because the IDC flowgates list is updated monthly and the IDC users can add temporary flowgates to it at any time, this is an inappropriate list to use. We appreciate the drafting team's attempt to resolve this issue by including the caveat "that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator." However, this really only confuses the matter and does not solve it. The Reliability Coordinator adds flowgates to manage real-time congestion. The Planning Coordinator does not. Per the NERC functional model, they do not even have a role in deciding which flowgates to add to the IDC. Flowgates are added to the IDC to mitigate existing, known congestion points not congestion points identified in a long-term planning study that may never materialize due to changing conditions. Thus, IDC flowgates should be specifically excluded. Now let us focus on the second component of flowgate. The second component is much like the first component in that it is a mathematical construct to analyze the impact of power flows on the BES except it is not required to be included in the IDC. There is nothing in the definition of a flowgate to give credence that it represents anything more that point to calculate power flows and the impact of transactions. Flowgates are primarily used to manage congestion on the system and to sell transmission system. Because it is convenient to select a group of lines as a proxy to sell transmission service or manage congestion does not mean that those group of lines represent a reliability issue. Thus, we do not believe any flowgates should be included in the list. Any true reliability issues can be identified through the TPL studies and those facilities that do not meet the performance requirements are what should be used. We do not support criterion B4. It exceeds what is required in the TPL standards and what is required per the reliability directive in Order 729. The TPL standards allow system operator intervention for category C3 contingencies between the two independent Category B contingencies. This standard should not exceed those requirements in the TPL standards. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test "must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning." Paragraph 80 states that "the test must be consistent with the general reliability principles embedded in the existing series of TPL" standards. Thus, exceeding the TPL standards could be argued as deviating from the directive. In response to comments that did not support this criterion during the first posting, the standards drafting team responded with "Testing multiple element contingencies while accounting for system adjustments between each element outage will

not yield any facilities to be subject to PRC-023 as long as TPL-003 system performance requirements are met." We think the drafting team missed a basic point about the standard. The issue is not whether the registered entity develops and documents corrective actions plans per TPL-003-0a R2 and R3. The issue is if the system as currently designed meets the performance requirements in TPL-003-0a R1 which allows for operator interventions on Category C3 contingencies. For those C3 contingencies that don't currently meet the performance obligations after operator interventions, the subject facilities would be included PRC-023-2 R6 list of facilities.
Group
Santee Cooper
Terry L. Blackwell
Yes
No
We appreciate the drafting team addressing this issue, and, in general, agree with our understanding of the intention of this requirement. However, the wording of the section should be a little clearer. Through asking questions about the intention of these statements, it is our understanding that, as long as the composite scheme (made up of all the relay elements protecting the transmission line) will still operate for a fault in a time that is compliant with the TPL standards, that this requirement is met. This may mean that a particular relay element may still be blocked, but there are other relay elements, possibly with a different time delay, that would still operate in an appropriate amount of time. As long as the total scheme protecting the element in question still meets all of the TPL and stability requirements for isolating the fault from the system, the operation of the scheme should be satisfactory. If this is still the intention, then it should be clarified in this requirement.
Yes
Yes
Yes
Yes
Yes
No
The criteria in Attachment B lack clarity. For example, B4 criteria for powerflow analysis does not specify a horizon. In addition, in B1 does that only apply to circuits that are monitored by you or the IDC? Assessing the post-contingency loading and determining if a facility rating is based on loading durations of specified time periods is too burdensome and would not provide much value.
Individual
Dan Rochester
Independent Electricity System Operator
No
Clarification is needed on whether criterion 10 requires a transformer to have load responsive protection to protect from mechanical damage. The wording in criterion 10 should be changed to "set transformer fault protection relay or transmission line relay on transmission line terminated with only a transformer." Is this criteria requiring that a transformer with only differential protection and no other load responsive remote protection be mitigated with additional load responsive protection?
Yes
No
As indicated in our previous comments, the FERC Directive asks for provision of this information to the TOP only. We question the need to go beyond what's being asked for in the Directive to require the responsible entities to provide this information to other entities (PC and RC). If a reliability need is not identified, we suggest that these two entities be removed from the requirement.
Yes
No
We agree that the PC should be held responsible for conducting the annual assessment, but we do not understand the need for including "if the Regional Entity has identified either of these Element types as critical facilities for the purposes of the Compliance Registry" in R6.2. We also do not understand the meaning of "as critical facilities for the purpose of Compliance Registry". There are established criteria for compliance registry, but we are not aware of what constitutes "critical facilities for the purpose of compliance registry". For the purpose of determining compliance with the relay loadability requirements, having the PC to make such an assessment and determination would suffice. If the intent is to limit the facilities to be assessed to only those that have been identified as "critical facilities for the purpose of compliance registry", then it implies that those that are not identified are not required to be assessed. This may in fact result in missing some facilities that may be critical from a relay loadability standpoint. Further, the term "critical facilities" is used very loosely in different standards, and can mean very different things for various applications and under various

circumstances. We suggest to remove ""if the Regional Entity has identified either of these Element types as critical facilities for the purposes of the Compliance Registry" from the requirement. For the same reason, we suggest the quoted phrase be removed from the Applicability Section, any other requirements in this standard, and Attachment B.
Yes
No
We commented on Criterion 6 (now B4) related to TPL-003 Category C contingencies in the previous posting but we see no evidence that our comment was addressed. We therefore reiterate our position. The PC and TP assess their future systems according to the performance requirements stipulated in the TPL standards, including those in TPL-003. We question the requirement to have Planning Coordinators assess the impact of double contingencies with no manual system adjustments in between since this is not required by TPL-003. This goes beyond the basic planning and design requirements and in our view should be removed from Criterion B4. We also believe Criterion B4 should be rewritten for greater clarity. The second bullet seems unnecessary since the post contingency loading on each circuit will not in fact be compared against its Facility Rating to determine applicability of PRC-023-2 but against the corresponding "applicability threshold". Also, the third bullet seems to conflict with the fourth, since the forth bullet allows for determining thresholds based on Facility Ratings that assume various loading durations, whereas the third bullet links determination of the threshold to the Facility Rating for a duration nearest four hours only. We therefore suggest the following alternative wording for B4: B4. Each circuit operated between 100 kV and 200 kV identified by applying the following procedure: B4.1Establish Thresholds of Applicability – (text of 4th bullet of B4) B4.2 Conduct Analysis – Conduct power flow analysis to simulate double contingency combinations selected by engineering judgment as indicated in TPL-003 Category C3. B4.3 Evaluate Applicability of PRC-023-2 – Compare post contingency loading of each circuit against its corresponding threshold determined in B4.1. Indicate the applicability of standard PRC-023-2 to each circuit for which the post contingency loading exceeds the corresponding threshold. B4.4 Exclusion - Radial circuits serving only load are excluded.
Group
Bonneville Power Administration
Denise Koehn
No
BPA believes that FERC does not fully understand how transformers are rated and applied on the Bulk Electric System. Therefore, we believe the concern they expressed in their NOPR and Order 733 regarding the reliability of the Bulk Electric System being jeopardized by operating a transformer at 150% of its nameplate rating is unfounded. In response to FERC's concern, NERC has modified Criterion 10, which now has two conflicting requirements—ensuring that there is no operation for one level of load and ensuring that there is operation for another level of load. In some cases, these two load levels overlap and both requirements cannot be achieved simultaneously. The requirement in Criterion 10 that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability is ambiguous. It is not clear how the mechanical withstand capability is to be determined. IEEE Standard C57.109 provides recommended transformer through-fault duration limits, but these do not represent the actual mechanical withstand capability of transformers. IEEE Standard C57.12.00 specifies that transformers shall be designed and constructed to withstand the mechanical and thermal stresses produced by a fault limited only by the transformer impedance, or for category III and IV transformers, transformer impedance plus system impedance, for a duration of two seconds. However, the standard specifies that for currents between rated current and maximum short-circuit current the allowable time duration should be obtained by consulting the manufacturer. These standards do not clearly indicate what the mechanical withstand capability of transformers are. Certainly, for many existing transformers, there is no available manufacturer's data for this either, and it is unclear how to comply with Criterion 10. BPA feels this is too ambiguous and exposes entities to an unnecessary risk of possibly being sanctioned based on the judgment of an auditor. BPA believes that FERC's concern about transformer damage at the loading levels addressed by this standard is unfounded and contradictory to the purpose of this standard. The purpose of PRC-023 is to prevent automatic relay operations--which could cause cascading outages and quickly deteriorate the reliability of the BES--during severe system loading conditions. Under these loading conditions it is desirable that system operators have time to take corrective action to mitigate system problems before automatic relay operations accelerate the problem into a blackout. IEEE Standard C57.109 indicates that transformers can sustain 200% of rated load for at least thirty minutes. If relays are set to operate in this range, they are at risk of tripping a transformer under emergency loading situations, which exasperates the very problem that PRC-023 is attempting to eliminate. Most utilities have developed emergency ratings for their transformers. When a transformer load exceeds a predetermined level, the system operators are alarmed so that they can take appropriate action. During stressed system conditions, allowing a critical transformer to operate up to these emergency ratings could prevent a blackout. Conversely, requiring relays to be set in this range could result in the automatic loss of critical transformers, thereby accelerating the collapse of the bulk electric system. The ability of transformers to carry load without thermal damage or with acceptable levels of loss of life has been under study for many decades. There are many variables, such as ambient temperature, duty cycle, acceptable loss of life, etc., that determine the load and duration that a transformer is capable of. It has been addressed in transformer design and relay protection standards. Many utilities have made considerable efforts to determine the appropriate levels of emergency loading for their transformers. The mechanical withstand capability of a transformer is not the relevant factor at the load levels addressed by PRC-023. BPA is concerned that we might be on the verge of superseding these many decades of research and experience with a poorly written, ambiguous, and inapplicable requirement because of the misunderstanding of the FERC commissioners. BPA suggests that NERC resist FERC's demands for setting relays to operate within the emergency operating capabilities of transformers. Additionally, BPA believes that there is no reason for FERC to be concerned with transformer overload protection. There is not a widespread problem with transformers being overloaded, and placing requirements on the industry for transformer protection results in an increased burden and expense to the industry with no resulting benefits. The subject of transformer loading has gained FERC's attention only as a result of its inclusion in PRC-023, and is not a problem for the BES—mostly because the industry has done the opposite of what FERC is now asking and not set transformer relays to operate in the emergency loading region. If transformer protection were an issue, it would be worthy

of an individual standard, separate from PRC-023, because it is too complex to address in a short paragraph such as Criterion 10. Finally, BPA believes that Requirement 1 is unclear. It states that each TO, GO, and DP shall use any one of the 13 criteria for any specific circuit terminal to prevent its phase protective relays from limiting transmission loadability. Does this mean that the requirements of Criterion 10 only apply if Criterion 10 is used as the basis for justifying the relay settings of a terminal? If the relay settings for a transformer-terminated line are justified by one of the other criteria, say Criterion 1, is an entity allowed to ignore the requirements of Criterion 10 for the transformer overcurrent relays? Are transformer relays for transformers that aren't part of a transformer-terminated line subject to Criterion 10? BPA recommends that the words "such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability" be removed from Criterion 10. In addition, if all transformer overcurrent relays—not just those for transformer-terminated lines—are subject to the requirements of Criterion 10 (as suggested by Attachment A), they need to be addressed in a separate requirement because the 13 criteria of Requirement 1 are not necessarily mandatory.
Yes
No
BPA does not understand why a list of such facilities must be provided each year. These facilities will not change very often, and a new list should only be required when changes are made to the old list. Please explain why you feel it is necessary.
No
Since a Registered Entity is already required to obtain the agreement of the Planning Coordinator, Transmission Operator, and Reliability Coordinator and to use the calculated circuit capability as the Facility Rating of the circuit as required by R3, BPA would like additional information regarding the purpose of providing the Regional Entity a list each year. What would they do with the list?
No
BPA feels the applicable date descriptions are too confusing and would like to see more clarity and simplification.
Yes
No
The evaluation method seems technically sound. The second category of applicable circuits, "Transmission lines operated below 100 kV and transformers with low voltage terminals connected below 100 kV ...", are not considered BES elements based on the latest definition and BPA does not believe that this category of circuits should be included.
Individual
Michael R. Lombardi
Northeast Utilities
No
Further clarification is needed for this criterion. Is it the intention of this criterion that all applicable transformers must have load responsive protection to prevent mechanical damage from a through fault? If load responsive protection for the transformer element does not presently exist, i.e. only differential protection exists for the transformer element, will load responsive transformer protection have to be added to comply with this criterion? It is also suggested that R1 Criterion 10 wording be changed to "Set transformer fault protection relays or transmission line relays on transmission lines terminated only with a transformer to ……." since it appears from the NERC Webinar on 11/23/10 that the intention was address the possible locations where phase protection for the transformer could exist and not infer that this protection was needed at both locations.
No
What is the expectation for verification that the out-of-step blocking elements allow tripping of phase protection relays for faults that occur duing the loading conditions used to verify transmission line relay loadability? It would be very costly and time consuming to verify proper operation of these blocking schemes for all of the various possible fault and loading combination scenarios for each application of this scheme.
Yes
Suggest clarification for Section 4.2.6 be added. That is, our review of the draft indicates that, as its title implies, this Standard primarily focuses on transmission relaying for lines and transformers. Nowhere does it mention generation relaying, per se, and the transformer relaying appears to be focused on "transmission" transformers and other transformers that have bi-directional flow capability. There is one sticking point, however. Section 4.2.6 seems to muddy the otherwise clear "transmission" directive in that it extends the applicability to: "4.2.6 Transformers with low voltage terminals connected below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry and the Planning Coordinator has determined are required to comply with this standard". While we believe that this was intended to pertain to transmission or load-serving transformers, due to ambiguity in the Standard this could be taken to mean transformers in facilities deemed "material to the reliability of the Bulk Power System." It could thus be applied (incorrectly, in our opinion) to generation facilities. We would also question why there would be a concern for the low voltage side of a GSU. Please clarify Section 4.2.6, as appropriate.
Yes
Yes
Yes

Yes
Yes
Individual
Armin Klusman
CenterPoint Energy
No
CenterPoint Energy disagrees with providing a list to Planning Coordinators, Transmission Operators, and Reliability Coordinators, as we cannot see any need and do not expect these entities would utilize this information in any manner.
No
CenterPoint Energy disagrees with providing a list, as we cannot see any need and do not expect the Regional Entity would have any use for this information. In discussions with Regional Entity personnel, they were unsure of what use they would have for this information.
No
(a) CenterPoint Energy recommends revising R6 to require Planning Coordinators to coordinate with associated Transmission Planners in the determination of which 100 – 200 kV elements must comply with this standard. (b) CenterPoint Energy recommends criterion B5 be deleted, as it is too broad and gives the Planning Coordinator too much discretion in determining other facilities which must comply with this Standard. In the case that criteria B5 is not deleted, CenterPoint Energy recommends that a process be required where Transmission Planners can appeal the inclusion of specific Transmission elements that must comply with this standard. (c) CenterPoint Energy recommends eliminating the un-capitalized term “critical” to remove any confusion with NERC CIP reliability standards. The voluntary NERC relay loadability review in 2006 used the term “operationally significant element” for elements 100 – 200 kV. CenterPoint Energy recommends using “operationally significant” wherever “critical” is used within PRC-023-2.
No
CenterPoint Energy believes Requirement 7 should be deleted from PRC-23-2, as it an Effective Date / Implementation Plan issue. Instead the wording should be included in PRC-023-2 in Effective Dates item 5.5 and within the Implementation Plan.
No
(a) Criterion B3 indicates any path that is used to supply off-site power to nuclear plants, as agreed to by the plant owner and the Transmission Entity. If the purpose of attachment B is to provide “bright line” criteria, then a negotiated agreement would not qualify as “bright line”. Additionally, off-site power requirements are meant to ensure safe shutdown of nuclear reactors in a system restoration event where transmission lines are lightly loaded. CenterPoint Energy recommends criterion B3 be deleted. (b) Considering situations where the transmission system may be at risk of cascading outages or voltage collapse, sub-200 kV elements should be considered operationally significant only whenever reasonably contemplated scenarios would cause high amperage and low voltage to be experienced on the elements. Criteria B4.a in Attachment B proposes loading exceeding 115% of a two or four hour rating following a double contingency, without manual system adjustments. CenterPoint Energy believes this is not a technically sound method to indicate if an element is operationally significant.
Group
New York Power Authority
Bruce Metruck
No
Clarification is needed on whether criterion 10 requires a transformer to have load responsive protection to protect from mechanical damage, either from internal faults, or through faults. If load responsive protection for the transformer element does not presently exist, i.e. only differential protection exists for the transformer element, will load responsive transformer protection have to be added to comply with this criterion? The wording in criterion 10 should be changed to “Set transformer fault protection relays or transmission line relays on transmission lines terminated only with a transformer to …….” Is this criteria requiring that a transformer with only differential protection and no other load responsive remote protection be supplemented with additional load responsive protection? The loading on phase angle regulators, and series reactors should be considered and mentioned. Also, there appears to be words missing in criterion 9 of R1: “the maximum current flow from the ? to the ? under any system configuration.” From the NERC Webinar on 11/23/10 the intention was to address the possible locations where phase protection for the transformer could exist and not imply that this protection was needed at both locations.
Yes
Yes
Yes
Yes

Yes
Yes
No
B2. Item B2 adds significant confusion to the process. The long term planning horizon may include transmission projects which have not even been built or alternative system configurations which do not exist, making it impossible for affected parties to set their relays appropriately. Suggested replacement language to avoid this issue: “Each circuit that is a monitored element of an IROL, assuming that all transmission elements are in service and the system is under normal conditions.” B3. This item indicates that the circuits to be considered are to be agreed to by the plant owner and the Transmission Entity. Attachment B is applicable to the Planning Coordinator. If this item is by agreement by the plant and the Transmission Entity it should be removed from Attachment B and placed elsewhere in the document. If this is intended to apply to the Planning Coordinator, Transmission Entity should be replaced with Planning Coordinator. Why does B3 only apply to Nuclear Power Plants? B4. This criterion is overly stringent and should be deleted. The system is neither planned nor operated to allow for two overlapping outages without operator action in between. If this criterion is retained, it should be made consistent with the requirements of TPL-003 where operator actions can be assumed between the first and second contingencies. Since a similar comment was made previously, more information is being provided following. 1. Since the system is neither planned nor operated to two overlapping outages in between, such testing may result in unsolved cases, or voltages well below criteria. In the case of an unsolved case, there are no flows to evaluate, making this standard impossible to apply. In the case of a solved case with voltages well below criteria, currents are likely to be incredibly high and therefore viewed as unrealistic. These concerns may limit the contingency selection to those which are not severe, eliminating any perceived benefit from this testing. 2. There is no guidance provided on how the system should be dispatched in the model upon which the overlapping contingencies are tested. This will result in significant discrepancies between the base assumptions used by the various Planning Coordinators. The contents of this standard should be reviewed to reflect the new definition of the Bulk Electric System.
Group
FirstEnergy
Doug Hohlbaugh
No
Criterion 10 does not take bidirectional load flow into consideration which could compromise the entity’s ability to provide backup protection for the transmission system. We suggest the following wording for criterion 10: “Set transformer fault protection relays and transmission line relays on transmission lines terminated only with a transformer such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability and so that the relays do not operate at or below the greater of: ♣ 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment for load flow from the normal source side to the normal load side. ♣ 115% of the highest operator established emergency transformer rating for load flow from the normal source side to the normal load side. ♣ 115% of the maximum current flow from the normal load side to the normal source side under any system configuration.” We also ask that the team consider similar wording be added to Criterion 11 as suggested above for consistency with Criterion 10. Criterion 9 seems to be missing some words in the phrase “flow from the to the under any system configuration”. It appears this should say “from the load to the system under any system configuration.”
Yes
Yes
No
FE recognizes that the standard drafting team introduced Requirement R5 in response to a FERC directive requiring NERC to document and make available upon request a list of protective relays set pursuant to Requirement R1, Criterion 12. We commend FERC in their Order 733 decision to retain Criterion 12 over accepting the preceding NOPR recommendation to remove it and support FERC’s desire in making information readily available on entities application of Criterion 12 for its own use and other interested parties. We are not opposed to providing our Regional Entity the information desired but believe this presents an administrative task that can be accomplished outside of a mandatory and enforceable reliability requirement. Since the reported data is for informational purposes and not a reliability need, we encourage the drafting team propose to NERC staff an equally efficient and effective alternative of having the Regional Entity periodically obtain the data through NERC’s Rules of Procedure, Section 1600 titled “Request for Data or Information”.
Yes
While we agree with the intent of Requirement R6, FE believes improvements can be made to simplify and clarify the R6 text. a. Items 6.1 and 6.2 can be removed as they are duplicative with the two bulleted items listed at the forefront of Attachment B. b. Item 6.3 is awkwardly written based on the circular reference to R6. Its suggested that Item 6.3 be re-written to say “Maintain a list of transmission Facilities operated below 200kV and deemed applicable to the PRC-023 standard per application of Attachment B” c. Requirement R6 and Attachment B text seem to mix and interchange references to Glossary of Term definitions “Elements” and “Facility”, although facility(ies) is often not capitalized, such that they are used synonymously. As one example R6 indicates “…determine which transmission Elements must comply with this standard …” compared to Attachment B which says “… to determine the facilities which must comply with this standard.” Sub items of R6 refer to keeping a list of “facilities” and not “Elements” as referenced in the parent R6 requirement. For greater consistency we suggest the use of the term “Facility(ies)” over “Element”. d. If the team believes a reference to a Planning Coordinator only needing to cover transmission facilities within their footprint is needed, such as

used in items 6.1 and 6.2 which are proposed for removal, the team could revise the parent R6 text to read " … to determine which transmission Elements [Facilities] in its Planning Coordinator area must comply with this standard." e. Replace the word "year" in item 6.5 with "planning study year". Its also recommended that the same change occur in R7, to better clarify what "year" is referring to in R7.
Yes
We support the minimum 24 month implementation timeframe because a responsible entity will need sufficient time to allow for any capital expenditures that may be required due to additional facilities identified by the Planning Coordinator.
Yes
No
FE proposes that criterion B1 be removed from Attachment B. We support criterion B3 as written and proposed revised versions of criterion B2 and B4. a. Item B1 implies all facilities operated below 200kV and associated with a Flowgate must comply with the PRC-023 standard. We support both MISO's and PJM's view that this criterion should be removed since Flowgates in their truest sense is used for economic and market transmission needs over reliability needs. Flowgates describe a designated point on the transmission system through which the Interchange Distribution Calculator (IDC) calculates the power flow from Interchange Transactions. While its recognized the drafting team attempted improve the Flowgate criteria by including a statement "that has been included to address a long-term reliability concerns, as confirmed by the applicable Planning Coordinator", it is FE's opinion that a Planning Coordinator does not play a role in adding or revising Flowgates used in the IDC and do not utilize Flowgates for long-term reliability planning purposes. Flowgates are a means of managing congestion and for identifying available transfer capability. Continued use of this criterion will only serve to confuse and complicate matters. b. Item B2 should be revised to include not only the monitored facilities associated with the IROL, but also any "contingent" facilities that may describe the IROL condition. For example, it is important to include the transmission facilities described in a NERC C3 contingency that may be associated with an IROL definition. A C3 contingency describes a N-1-1 condition with system adjustments permitted in between the 1st and 2nd contingency. It is necessary to ensure that the 2nd contingent facility does not prematurely trip due to a relay loadability limitation. For greater consistency with terminology used in the FAC-014 standard, Requirement R5.1 we propose the following for criterion B2: "B2. Each circuit monitored as critical to the derivation of an IROL and each circuit associated with the Contingency(ies) that describe the need for the IROL." c. We support criterion B3 as written. d. In regards to criterion B4, FE supports the team's recommendation for the Planning Coordinator to perform a modified NERC Category C3 analysis to further identify sub 200kV facilities applicable to the PRC-023 standard. However, the sub-bullets identifying various loading thresholds depending on the Facility rating is overly complicated and creates undue burden for the Planning Coordinator performing the study. We propose that the team simplify this criterion to clarify the applicable facilities are those that exceed 130% of their continuous emergency rating for the modified NERC Category C3 test.
Individual
Gregory Campoli
New York Independent System Operator
Yes
No comment from the PC & RC perspective, the TOs are responsible for designing phase protection schemes appropriate to their systems
No
PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1, and therefore unnecessary. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings including those limited by relays.
Yes
No
Wording for R6.2 is confusing. It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV. This information is not readily available and there is no requirement for the Regional Entity to communicate it to them. Revise to clearly state the intent of the requirement is for registered entities to report to Regional Entities those applicable facilities below 100kV and that the requirement for Regional Entities is only to make that list available. There is no justification given in R6.4 for the need to identify facilities for which criterion B4 applies and there is no further required action as a result of this information. Thus, it is purely administrative and should be removed. Registered entities should never be subject to potential sanctions for violations of purely administrative portions of requirements.
No
R7 is unnecessary as the applicability section of the standard is clear that the standard applies to those circuits identified in R6. This requirement could be construed as potential for double jeopardy because failure to comply with Requirements 1-5 represents a violation of both Requirement 7 and Requirements 1-5.
Yes
No
Flowgates are primarily used to manage congestion on the system and to sell transmission system. Because it is convenient to select a group of lines as a proxy to sell transmission service or manage congestion does not mean that those group of lines represent a reliability issue. Thus, flowgates should not be included in the list as currently specified in

B1. Any true reliability issues can be identified through the TPL studies and those facilities that do not meet the performance requirements are what should be applicable here. B2 adds significant confusion to the process. The long term planning horizon may include transmission projects which have not even been built or alternative system configurations which do not exist, making it impossible for affected parties to set their relays appropriately. Suggested replacement language to avoid this issue: “Each circuit that is a monitored element of an IROL, assuming that all transmission elements are in service and the system is under normal conditions.” B3 indicates that the circuits to be considered are to be agreed to by the plant owner and the Transmission Entity. Attachment B is applicable to the Planning Coordinator. If this item is by agreement by the plant and the Transmission Entity it should be removed from Attachment B and placed elsewhere in the document. If this is intended to apply to the Planning Coordinator, Transmission Entity should be replaced with Planning Coordinator. The B4 criterion is overly stringent and should be deleted. The system is neither planned nor operated to allow for two overlapping outages without operator action in between. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test “must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning.” Paragraph 80 states that “the test must be consistent with the general reliability principles embedded in the existing series of TPL” standards. If this criterion is retained, it should be made consistent with the requirements of TPL-003 where operator actions can be assumed between the first and second contingencies.
Individual
Darryl Curtis
Oncor Electric Delivery Company LLC
No
In paragraph 209 of Order No 733 it states: Since Requirement R1.10 applies to any topology, it must be robust enough to address the reliability issues of any topology. In light of the above statement criterion 10 of Requirement R1 should be modified to read as follows: Set transformer fault protection relays and transmission line relays used for transformer fault protection such that the protection settings do not expose the transformer to fault level and duration that exceeds its mechanical withstand capability and so that the relays do not operate at or below the greater of: By eliminating the special topology of “transmission lines terminated only with a transformer” from criterion 10 it eliminates any ambiguity that the criterion only applies to special transmission line cases and complies with the FERC assertion that the Requirement “applies to any topology.” Oncor like other Transmission Owners provides autotransformer protection from possible thermal damage due to either prolonged through faults or load with its transformer overload protection relays. Protection of all autotransformers from fault level and duration that exceeds their mechanical withstand capability is provided by the redundant phase and ground relay settings of the local zones of protection coupled with local breaker failure protection. For prolonged faults that are outside the local zones of protection (not threatening damage to the transformer by exceeding the mechanical withstand capability of the transformer) or where loads exceed the thermal rating of the transformer the phase and ground transformer overload protection relays protect the transformer from thermal damage. Based on the fact that at many locations a transformer is protected by local Protection Systems from prolonged “Close in” phase and ground through faults that might be within the fault level and duration that exceeds their mechanical withstand capability, criterion 11 of Requirement R1 should be modified as follows: For transformer overload protection relays that do not comply with the loadability or mechanical withstand capability components of Requirement R1, criterion 10 set the relays according to one of the following: If transformer protection from fault level and duration that exceeds a transformer’s mechanical withstand capability is provided by other Protection Systems, set the transformer overload protection settings to not expose the transformer to current level and duration that exceeds its thermal withstand capability and so that the relays do not operate at or below the greater of 150% of the applicable maximum transformer nameplate rating (expressed in amperes), including the forced cooled ratings corresponding to all installed supplemental cooling equipment or 115% of the highest operator established emergency transformer rating. Set the relays to allow the transformer to be operated at an overload level of at least 150% of the maximum applicable nameplate rating, or 115% of the highest operator established emergency transformer rating, whichever is greater, for at least 15 minutes to provide time for the operator to take controlled action to relieve the overload. Install supervision for the relays using either a top oil or simulated winding hot spot temperature element set no less than 100° C for the top oil temperature or no less than 140° C for the winding hot spot temperature. Oncor believes that criterion 10 of Requirement R1 needs to be further modified as stated above to ensure that it applies to transmission lines of any topology and not just to transmission lines terminated only with a transformer. Oncor also feels that modifying criterion 10 of Requirement R1 by adding a requirement to ensure that protection settings do not expose transformers to fault level and duration requires that, for the reasons stated above, criterion 11 of Requirement R1 must be modified as noted above.
Yes
No
Oncor feels that the Requirement R4 is too cumbersome for the Registered Entities who have to, every 12 to 15 months, provide to the Planning Coordinator, Transmission Operator and Reliability Coordinator massive amounts of information that rarely changes. Also by allowing up to 15 months between reports to the Planning Coordinator, Transmission Operator and Reliability Coordinator of relay setting changes made by Registered Entities these Operators and Coordinators are deprived of knowing changes to loading limitations for up to 15 months. To overcome the problems with Requirement R4 of the present version PRC-023-2 Oncor has two specific suggestions for improvement. First, Requirement R4 should be changed to have a one time requirement for Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability to provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with a list of facilities associated with those transmission line relays. Second, Requirement R4 should be changed to require Each Transmission Owner, Generator Owner, and Distribution Provider that chooses to use Requirement R1 criterion 2 as the basis for verifying transmission line relay loadability to provide its Planning Coordinator, Transmission Operator, and Reliability Coordinator with any changes (additions, deletions or modifications) to the one time list of facilities associated with those transmission line relays within 30 days changes are made to list. By using the proposed changes to R4 listed above, the

only information that needs be transferred between the Registered Entities and the Operators and Coordinators following the initial exchange of information are changes made to the initial information. By requiring the Registered Entities to notify the Operators and Coordinators shortly after changes are made the up to 15 month delay getting modifications to them is eliminated.
No
Oncor feels that the Requirement R5 is too cumbersome for the Registered Entities who have to, every 12 to 15 months, provide the Regional Entity a list of all the facilities that under Requirement R1 criterion 12 are limited by the requirement to adequately protect the transmission line and cannot meet loadablity. It would better for the Registered Entities to provide a one time list to its Regional Entity and then provide to the Regional Entity any additions or deletions to the list no more than 30 days following any changes to the relaying what would remove or add a transmission line to the list.
Yes
Yes
Individual
Chris de Graffenried
Consolidated Edison Co. of NY, Inc.
No
R1 - Clarification is needed on whether criterion 10 requires a transformer to have load responsive protection to protect from mechanical damage. The wording in criterion 10 should be changed to “set transformer fault protection relay or transmission line relay on transmission line terminated with only a transformer.” Is this criterion requiring that a transformer with only differential protection and no other load responsive remote protection be mitigated with additional load responsive protection? The loading on phase angle regulators, and series reactors should also be considered and mentioned. Also, there appears to be words missing in criterion 9 of R1: “the maximum current flow from the ? to the ? under any system configuration.”
No
R2 - What is the expectation for verifying that the out-of-step (OOS) blocking elements allow tripping of phase protection relays for faults that occur during the loading conditions used to verify transmission line relay loadability? It would be costly and time consuming to verify this. To comply with this requirement, utilities may have to remove OOS protections all together.
Yes
Yes
Yes
Yes
Yes
No
Attachment B - Why does B3 only apply to Nuclear Power Plants only?
Individual
Kirit Shah
Ameren
No
This additional statement is not necessary and already covered in R1 with the statement: ‘while maintaining reliable protection of the BES for all fault conditions.’
Yes
No
This requirement is redundant with Standards FAC-008-1 and FAC-009-1. The existing standards already cover ratings methodologies and reporting of facility ratings to the appropriate entities. In addition, these two standards already require consideration of relaying equipment as one component in developing ratings methodologies and in reporting of those ratings.
No
Given that protective relaying equipment is already covered as one component in developing ratings in standards FAC-008-1 and FAC-009-1, it is not clear that there is a reliability based need for the information required to be provided in Requirement R5. Therefore, this requirement should be removed from the proprosed standard.
No
Section 6.2 is unclear and seems arbitrary in the statement ‘if the Regional Entity has indentified either of these Element

types as critical facilities for the purpose of the Compliance registry'. A clear test is lacking.
No
As this requirement is structured, it creates a potential for double jeopardy should one of the other requirements mentioned (R1 through R5) be violated. This requirement is not needed and should be removed from the proposed standard.
No
Section 1.6 is contrary to section 2.0 and seems arbitrary. Why is a communication system for a current-based scheme treated to a higher standard than other communications scheme? The communications scheme reliability is covered through the maintenance and misoperations analysis standards.
No
Criterion B1, which has been modified to encompass only flowgates which have been included to address long-term reliability concerns, while a step in the right direction, does not go far enough. Because flowgates are primarily utilized to manage congestion and assist in the process of transmission service sales, rather than investigate reliability issues more appropriately conducted via study work covered under the TPL standards, this criteria should be eliminated. Criterion B4 as worded still exceeds the requirements of Reliability Standard TPL-003 by requiring simulating double contingencies with no operator intervention permitted. While such simulation would be done as part of assessment work under TPL-003 for fast-acting contingencies involving multiple circuits, such as Category C1 bus faults, C2 breaker failures, and C5 double-circuit tower outages, such simulations are not necessary under TPL-003 with Category C3 events which consist of separate Category B events with intervening operator action. Such simulations should not be made necessary as part of the proposed PRC-023-2 standard. Rather, should the TPL-003 performance requirements not be met for Category C3 contingencies with operator intervention considered, those facilities could be included in the list of facilities specified in PRC-023-2 Requirement R6.
Individual
Saurabh Saksena
National Grid
No
National Grid seeks clarification on whether criterion 10 requires transformer to have load responsive protection to protection from mechanical damage. The wording in criterion 10 should be changed to "set transformer fault protection relay or transmission line relay on transmission line terminated with only a transformer." For example, is this criteria requiring that a transformer with only differential protection and no other load responsive remote protection be mitigated with additional load responsive protection?
No
National Grid seeks clarification on what is the expectation for verifying that the out-of-step blocking elements allow tripping of phase protection relays for faults that occur during the loading conditions used to verify transmission line relay loadability? It would be costly and time consuming to verify this. To comply with this requirement, utilities may have to remove OOS protections all together.
Yes
Yes
Yes
Yes
Yes
No
1. As per Section 4.2.3 (also included as bullet point 2 of Applicable circuits in Attachment B) "Transmission Lines operated below 100 kV that Regional Entities have identified as critical facilities for the purposes of the Compliance Registry and the Planning Coordinator has determined are required to comply with this standard." National Grid believes that voltage levels less than 100 kV are outside NERC's jurisdiction and hence, requirements related to sub 100 kV levels should not be part of NERC standards. 2. National Grid recommends a provision in the standard which allows entities an option to 1. Either comply with standard for all applicable elements or 2. Apply the methodology as stated in Attachment B. The rationale is that entities that choose to comply with PRC-023 for all applicable elements should be recognized and should be exempted from complying with the methodology in Attachment B. 3. Requirement R6 of the proposed standard requires entities to apply criteria in Attachment B and conduct assessments with no more than 15 months between assessments to determine which transmission elements must comply with this standard. TPL standard which is considered to be the primary standard dealing with designing and planning of the system allows an interim assessment to rely on previous years simulations and does not mandate a stringent 15 month period between assessments. National Grid believes that an auxiliary PRC-023 standard should not present more stringent requirements than the primary TPL standard and recommends to remove the "15 month between assessments" requirement.
Individual
Jeff Billo
ERCOT ISO
Yes

Yes
No
It is not clear what the Planning Coordinator and Reliability Coordinator is supposed to do with this information.
No
No
ERCOT ISO is unclear, as to what is meant by the reference to the Compliance Registry. Additionally, ERCOT ISO feels the Regional Entities are not the appropriate entities to declare which elements (below 100kV) should be considered critical. For 6.2 and Attachment B, ERCOT ISO suggests completely removing the existing language pertaining to facilities operated below 100kV.
Yes
Yes
No
In regards to criteria B1, the Texas Interconnection does not have comparable monitored elements. All transmission elements are treated and monitored equally in ERCOT at this time. The only exception to this is IROLs which are already covered in criteria B2. Therefore, ERCOT ISO suggests removing the reference to the Texas Interconnection in criteria B1. In regards to criteria B3, the Planning Coordinator does not necessarily know the circuit paths for off-site power for nuclear plants. The Transmission Owners would be better able to identify these circuits. ERCOT ISO suggests moving this criteria into section 4.2 (Applicability, Facilities). ERCOT ISO also suggests revising the language so that it does not state that a "circuit must comply with the standard" since it is an entity that must comply with the standard. ERCOT ISO suggests replacing this language with "circuit will be applicable to this standard" throughout Attachment B.
Individual
Terry Harbour
MidAmerican Energy
Yes
Yes
No
I don't believe this requirement is needed. Limiting a relay setting to 115% of the associated transmission line's highest seasonal 15 minute rating does not equate to a line that will trip before the operator has time to intervene. It does not mean the line will trip in 15 minutes. In fact, the operator should be taking action well in advance of reaching a 15 minute limit and the operator is likely only using the 15 minute rating in extreme circumstances. Furthermore, PRC-023-2 R3 and R4 are duplicative of FAC-008-1 and FAC-009-1. FAC-008-1 and FAC-009-1 already collectively require the Transmission Owner and Generator Owner to establish a facilities ratings methodology, rate its facilities consistent with its methodology and to communicate those ratings and methodology to its Planning Coordinator, Reliability Coordinator and Transmission Operator. More specifically FAC-008-1 R1.2.1 requires the Transmission Owner and Generator Owner to consider relay protective devices in its ratings methodology and FAC-009-1 R2 requires the communication of the ratings including those limited by relays. As a result, neither PRC-023-2 R3 nor R4 is even needed. We assume the drafting team must be aware of these FAC standard requirements because they did not even require reporting to the Reliability Coordinator, Planning Coordinator and Transmission Operator of those circuits that are actually limited by the relay per criterion 12. We agree that FAC-008-1 and FAC-009-1 collectively establish the necessary requirements to compel the Transmission Owner and Generator Owner to communicate these relay limited circuits and that no additional requirements are necessary.
No
While we don't necessarily have an issue with the equipment owner communicating these relay limited circuits to the Regional Entities, we don't believe this is needed for reliability and therefore it should not be included in the reliability standard. Given that it is unclear what the information will even be used for, if it will be needed long-term, and that it is likely will not change much, if at all, from year to year, we believe a data request through NERC's Rules of Procedure section 1600 would be more appropriate. In that way, we don't have to modify the standard later when NERC and the Regions determine they don't need the data annually.
No
Sections 4.2.2, 4.2.3, 4.2.6, R6, and Attachment B needs to be modified with a superior alternative than the FERC recommendation to assign the PC the responsibility to determine a sub-200 kV critical facility test. NERC needs to re-assign this to the Transmission Owners and Operators as the entities that properly perform transmission planning analysis. The PC's aren't the proper entities that understand and perform the proper analyses. Therefore the superior alternative is to re-assign the responsibility to the party that understand what is truly critical and why. At a minimum Transmission Owners and / or Operators should be added to ensure that the entities that best understand the operation of the electric grid. It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV that are part of the Bulk Electric System. This information is not readily available and there is no requirement for the Regional Entity to communicate it to them. Thus, inaction by the auditor (i.e. Regional Entity) could actually cause the Planning Coordinator to violate this requirement. This is clearly a conflict of interest. Why does the Planning Coordinator need to identify which circuits are identified per criteria B4? There is no justification given for this need and there is nothing else that appears to require action as a result of this information. Thus, it is purely administrative and should be removed. Registered entities should never be subject to potential sanctions for violations of purely

administrative portions of requirements. Why does the Planning Coordinator need to provide this information to the Reliability Coordinator? There is nothing for the Reliability Coordinator to do with the information. The Reliability Coordinator only needs to be informed if equipment becomes derated and then that should occur through the normal communication of ratings per FAC-009-1.
No
We do not believe that R7 is needed. The applicability section of the standard is clear that the standard applies to those circuits identified in R6. This requirement could be construed as potential for double jeopardy because failure to comply with Requirements 1-5 for represent a violation of both Requirement 7 and Requirement 1-5.
Yes
No
Criterion B1 should be eliminated as there is no technical basis to show that "flowgates" are anything more than a measure of congestion. The loss or potential loss of a flowgate won't necessarily result in any more or less reliability impact to the BES than the loss of any other BES element. Therefore a superior criteria for Attachment B is to actually base critical elements upon the Federal Power Act Section 215 criteria of instability, uncontrolled separation, or cascading, which is related to the B2 criteria and being an IROL. Measuring the potential exceedance of TPL criteria as written is also acceptable. MidAmerican notes the NERC Attachment B criteria exceed the FERC directive to follow TPL criteria in Order 729.
Group
IRC Standards Review Committee
Ben Li
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No
Wording for R 6.2 is confusing. Revise to clearly state the intent of the requirement is for registered entities to report to Regional Entities those facilities below 100KV that the requirements should apply to and that the requirement for Regional Entities is only to make that list available It is not clear how the Planning Coordinator is supposed to know which facilities the Regional Entity has identified that are below 100 kV that are part of the Bulk Electric System. This information is not readily available and there is no requirement for the Regional Entity to communicate it to them. Thus, inaction by the auditor (i.e. Regional Entity) could actually cause the Planning Coordinator to violate this requirement. This is clearly a conflict of interest. Why does the Planning Coordinator need to identify which circuits are identified per criteria B4? There is no justification given for this need and there is nothing else that appears to require action as a result of this information. Thus, it is purely administrative and should be removed. Registered entities should never be subject to potential sanctions for violations of purely administrative portions of requirements. Why does the Planning Coordinator need to provide this information to the Reliability Coordinator? There is nothing for the Reliability Coordinator to do with the information. The Reliability Coordinator only needs to be informed if equipment becomes derated and then that should occur through the normal communication of ratings per FAC-009-1. Note: CAISO does not sign on to the above comments.
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Yes
No
We disagree with B1 which includes monitored elements of flowgates. Flowgates may not always be used for reliability

purposes and may be temporary to address certain economic conditions. While we appreciate the drafting team's effort to refine the flowgate criteria from the last posting, the modifications do not go far enough and still do not reflect the use of flowgates. NERC's definition of flowgate includes two components. Let's focus on the first component which represents those flowgates defined in the IDC. Because IDC flowgates list is updated monthly and the IDC users can add temporary flowgates to the IDC at any time, this is an inappropriate list to use. We appreciate the drafting team's attempt to resolve this issue by including the caveat "that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator." However, this really only confuses the matter and does not solve it. Reliability Coordinators add flowgates to manage real-time congestion. Planning Coordinators do not. Per the NERC functional model, they do not even have a role in deciding which flowgates to add to the IDC. Flowgates are added to the IDC to mitigate existing, known congestion points not congestion points identified in a long-term planning study that may never materialize due to changing conditions. Thus, IDC flowgates should be specifically excluded. Now let us focus on the second component of flowgate. The second component is much like the first component in that is it a mathematical construct to analyze the impact of power flows on the BES except is not required to be included in the IDC. There is nothing in the definition of a flowgate to give credence that is represents anything more that point to calculate power flows and the impact of transactions. Flowgates are primarily used to manage congestion on the system and to sell transmission system. Because it is convenient to select a group of lines as a proxy to sell transmission service or manage congestion does not mean that those group of lines represent a reliability issue. Thus, we do not believe any flowgates should be included in the list. Any true reliability issues can be identified through the TPL studies and those facilities that do not meet the performance requirements are what should be used. We do not support criterion B4. It exceeds what is required in the TPL standards and what is required per the reliability directive in Order 729. The TPL standards allow system operator intervention for category C3 contingencies between the two independent Category B contingencies. This standard should not exceed those requirements in the TPL standards. Paragraphs 79 and 80 of FERC Order 729 contain the relevant directives regarding the Planning Coordinator test. Paragraph 79 states that the test "must include or be consistent with the system simulations and assessments that are required by the TPL Reliability Standards and meet the system performance levels for all Category of Contingencies used in transmission planning." Paragraph 80 states that "the test must be consistent with the general reliability principles embedded in the existing series of TPL" standards. Thus, exceeding the TPL standards could be argued as deviating from the directive. The directive is to be consistent not exceed. Exceeding the TPL standards is not consistency. In response to comments that did not support this criterion during the first posting, the standards drafting team responded with "Testing multiple element contingencies while accounting for system adjustments between each element outage will not yield any facilities to be subject to PRC-023 as long as TPL-003 system performance requirements are met." We think the drafting team missed a basic point about the standard. The issue is not whether the registered entity develops and documents corrective actions actions plans TPL-003-0a R2 and R3. The issue is if the system as currently designed meets the performance requirements in TPL-003-0a R1 which allows for operator interventions on Category C3 contingencies. For those C3 contingencies that don't currently meet the performance obligations after operator interventions, the subject facilities would be included PRC-023-2 R6 list of facilities. Note: CAISO does not sign on to the above comments.
Individual
Alice Ireland
Xcel Energy
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
B1) The NERC book of flowgates for the Eastern Interconnection includes a combination of permanent and temporary flowgates. This criteria should only use the permanent flowgates and the text should be modified as indicated to reflect that. Each circuit that is a monitored Element of a permanent flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection as defined by the Regional Entity, or a comparable monitored Element in the Texas Interconnection or Québec Interconnection, that has been included to address long-term reliability concerns, as confirmed by the applicable Planning Coordinator. B3) This appears to link to the NUC-001 standard. We would suggest the following modification: "Each circuit that forms a path (as agreed to by the plant owner and the Transmission Entity) to supply off-site power to nuclear plants as established in the NPIR for NUC-001." B5) We suggest removing this one as it is too open ended and open to interpretation as to which additional circuits should be considered. If there are additional criteria that are determined later that should be included, then we suggest they be added by either a regional standard or a SAR to modify the NERC standard.