NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

# Project 2015-10 Single Points of Failure

## Consideration of Comments

### Introduction

The standard drafting team (SDT) appreciates industry comments on the proposed Reliability Standard, TPL-001-5. The SDT considered the comments submitted during the initial posting of the proposed Reliability Standard, and has revised the standard accordingly.

The System Protection and Control Subcommittee (SPCS) and the System Analysis and Modeling Subcommittee (SAMS) conducted an assessment of protection system single points of failure in response to FERC Order No. 754, including analysis of data from the NERC Section 1600 Request for Data or Information. The assessment confirms the existence of a reliability risk associated with single points of failure in protection systems that warrants further action.

Additionally, the two directives from FERC Order No. 786 (p. 40 and p. 89) and updates to the MOD reference in Requirement R1, Measure M1 and the Violation Severity Levels sections have been added to the scope of the project.

### Response to Comments – Summary Responses

The SDT has carefully reviewed and considered each stakeholder comment and has revised language where suggested changes are consistent with SDT intent and industry consensus. Also, several commenters suggested non-substantive language changes. The SDT has carefully considered each such comment and has implemented revisions to further clarify the language where needed. The SDT has addressed each comment and has provided below, in summary form, a response to each question.

# Consideration of Comments

Project 2015-10 Single Points of Failure | TPL-001-5

**Associated Ballots:** 2015-10 Single Points of Failure TPL-001-5 IN 1 ST

There were ## sets of responses, including comments from approximately ## different people from approximately ## companies representing # of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Senior Director of Standards, Howard Gugel (via email) or at (404) 446-9693.

1. Do you agree that an associated timetable for implementation of actions needed to prevent the System from Cascading (TPL-001-5 Requirement R4, Part 4.2.2.1) and an annual review of implementation status (TPL-001-5 Requirement R4, Part 4.2.2.2) should be required when analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column?

2. Do you agree that the requirements of the proposed TPL-001-5 Requirement R4, Parts 4.2.2.1 and 4.2.2.2, including an implementation timetable and annual review of implementation status, should not and do not mandate actual implementation of actions identified as needed to prevent the System from Cascading? For example, do you agree that a capital project is not required to be implemented by Requirement R4, Parts 4.2.2.1 and 4.2.2.2, even if the capital project is the only feasible action available to prevent the System from Cascading when analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column?

3. Do you agree with the omission, as proposed in TPL-001-5 Requirement R4, Part 4.2, of a requirement similar to that of Requirement R2, Part 2.7, which states that the planned System shall continue to meet the performance requirements in Table 1 in subsequent Planning Assessments?

4. Do you agree with including Table 1 Footnote 13 a., "[a] single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, *e.g.*, sudden pressure relaying", and its limitation to only the specific single protective relay and not to other elements of the associated Protection System?

5. Do you agree with the inclusion of Table 1 Footnote 13 b. & c. stipulation, “which is not monitored or not reported”, and that it conveys the expectation that the monitoring and reporting is sufficient to result in prompt remediation addressing the failure status of the associated equipment?

6. Do you agree with the inclusion of Table 1 Footnote 13 d., and that it, in conjunction with defined terms, identifies what constitutes all of the elements of, “A single control circuitry associated with protective functions including the trip coil(s) of the circuit breakers or other interrupting devices.”?

7. Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that modify which known outages shall be represented in System models from those “with a duration of at least six months” to those selected by the Planning Coordinator (PC)/Transmission Planner (TP) “in consultation with” their Reliability Coordinators (RCs).

8. Do you agree with omitting the Reliability Coordinator (RC) from the applicability of the TPL-001-5 standard given that Requirement R1, Part1.1.2 requires consultation between the TP/PC and the RC to determine which known outages to select for representation in System models?

9. FERC Order No. 786 Paragraphs 40-45 direct modification to address significant planned maintenance outages with durations less than 6 months in planning assessments.   Are you aware of an existing standard/requirement, consistent with industry practice and applicability that requires review and coordination of significant known maintenance outages less than 6 months in duration for inclusion in System models (TPL 001-4 Requirement R1 Part R1.1.2)?

10. Do you agree with the 36 month implementation period to address all Requirements except for Requirement R4, Part 4.2, and Requirement 2, Part 2.7 associated with the modified P5 events further defined in the redline changes to Footnote 13.

11. Do you agree with the 60 month implementation plan for Requirement 4, Part 4.2 and Requirement 2, Part 2.7 associated with the modified P5 events further defined in the redline changes to Footnote 13.?

12. In looking at all proposed recommendations from the standard drafting team, are the proposed changes a cost effective approach which meets the FERC directives? (*see* *Cost Effectiveness Background Document*)

13. Are you aware of any other governing documents that could be in conflict with the current proposal for this draft of the standard?

14. Do you have any other general recommendations/considerations for the drafting team?

## Consideration of Comments – Summary Responses

## Question 1: Associated Timetable and Annual Review Requirement R4 Summary Response

*1. Do you agree that an associated timetable for implementation of actions needed to prevent the System from Cascading (TPL-001-5 Requirement R4, Part 4.2.2.1) and an annual review of implementation status (TPL-001-5 Requirement R4, Part 4.2.2.2) should be required when analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column?*

### Extreme Event

There is a suggestion to remove implementation status and timetables, also extreme event 2e – 2h or three-phase fault followed by a protection failure is a low probability event and should have the same requirements as other extreme events.

**SDT Response:** The SDT agrees to remove implementation status and timetables. However, since FERC Order No. 754 resulted in follow-up analysis by the industry and the SPCS and SAMS assessment of additional analysis recommended three-phase faults be analyzed. Based on the reliability risk, the SDT decided to make the three -phase fault followed by a protection failure a P8 event with no Cascading allowed or a Corrective Action Plan (CAP) requirement.

### PRC Standard Requirement

Why this requirement isn't part of the PRC standards, but is instead proposed for standard TPL-001?

**SDT Response:**

Project 2015-010 SAR does not allow for changes to any NERC standards other than TPL-001.

### Requirement of CAP

There appears to be very little difference between 4.2.1 and 4.2.2 other than making a list and establishing an implementation timetable that would be meaningless if there is no intent to implement the solution. The current TPL-001-4 wording is sufficient unless there is a desire to require development and implementation of a Corrective Action Plan for certain events and circumstances, in which case, as previously suggested, the contingency should be moved from the extreme event category to a planning contingency category. Otherwise the wording in the current standard regarding extreme events that are found to result in cascading and/or instability should not be modified. There is confusion or lack of clarity around whether a CAP is required for the extreme event 2e – 2h.

**SDT Response:**

The SDT agrees to remove implementation status and timetables. However, since FERC Order No. 754 resulted in follow-up analysis by the industry and the SPCS and SAMS assessment of additional analysis recommended three-phase faults be analyzed. Based on the reliability risk, the SDT decided to make the three -phase fault followed by a protection failure a P8 event with no Cascading allowed or a Corrective Action Plan (CAP) requirement.

### NERC Glossary Term

"Action" is not a defined term. SDT should write what they mean by "Action".

**SDT Response:**

The SDT removed the reference to "Action" other than what is in the NERC Glossary for "Corrective Action Plan".

### CAP for Low Probability Event

It is not economically justifiable to require a CAP for low probability events. The SDT did not consider the cost and other factors.

**SDT Response:**

FERC Order No. 754 resulted in follow-up analysis by the industry and the SPCS and SAMS assessment of additional analysis recommended three-phase faults be analyzed. Based on the reliability risk, the cost of redundant relays, redundant trip coils, monitoring of communications and/or monitoring of DC supply is lower than the cost of transmission lines or transformers. Adding redundant protection improves the reliability of the Bulk Power System (BPS) at lower costs than other construction projects.

### Shunt Devices

Add shunts to the list of 2e-2h list of extreme events.

**SDT Response:**

The SDT agrees with this and shunts were added to the next version of the standard. However, the SDT decided to make the disturbance a P8 planning event and requiring CAPs.

### Transmission Planner Process

The review should follow the designated Transmission Planner's existing processes that have already been developed. This review should be rolled into that process.

**SDT Response:**

The SDT agrees and made the event a P8 event which will follow similar reviews and processes as other planning events.

### Adjustable Time Frame

Recommend the drafting team adds language to section 4.2.2.2 to clarify during the review process pertaining to the Planning Assessments for continued validity and implementation status that an adjustable time frame would always be taken into consideration.

**SDT Response:**

The SDT agrees with this and it is addressed by making a three phase fault followed by a protection failure a P8 planning event.

### Q1 Additional Comments

**Additional Comment #1**
Commenter does not agree with separating out the extreme event in 2e-2h for something between a CAP and no CAP.

**SDT Response:**
Standard Drafting team agrees with this comment and will be making a three-phase fault followed by a protection system failure a P8 planning event.

**Additional Comment #2**
The term “Planning Assessment” is defined in the NERC Glossary as a “documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies.” We believe these studies should not be used as a tracking mechanism for Corrective Action Plans, and that an adjustable time frame should be considered during subsequent reviews.

**SDT Response:**
The SDT agrees and made the event a P8 event which will follow similar reviews and processes as other planning events.

**Additional Comment #3**
No value added in extending the requirement to include event categories 2e-2h.

**SDT Response:**
FERC Order No. 754 resulted in follow-up analysis by the industry and the SPCS and SAMS assessment of additional analysis recommended a three-phase faults be analyzed. Based on the reliability risk, the cost of redundant relays, redundant trip coils, monitoring of communications and/or monitoring of DC supply is lower than the cost of transmission lines or transformers. Adding redundant protection improves the reliability of the BPS at lower costs than other construction projects.

**Additional Comment #4**
There is risk with the proposed changes of the single point of failure (SPF) language that will not significantly improve reliability. There is likelihood this change may even reduce reliability by having the CAPs force entities to redirect its limited resources away from other important reliability needs to solve SPF identified issue. Further, implementation of the CAPs may likely cause significant mis-ops while system protection systems are being modified to eliminate SPFs thus reducing reliability and increase risk to the transmission system. We would also like to point out that there is no corresponding directive from FERC in the SAR.

**SDT Response:**

FERC Order No. 754 resulted in follow-up analysis by the industry and the SPCS and SAMS assessment of additional analysis recommended three-phase faults be analyzed. Based on the reliability risk, the SDT decided to make the three-phase fault followed by a protection failure a P8 event with no Cascading allowed. The costs vs. benefit or resource requirements vs benefit is difficult to quantify since the reliability risk to the BPS is difficult to quantify in costs alone.

## Question 2: Associated Timetable and Annual Review Requirement R4 Summary Response

*2. Do you agree that the requirements of the proposed TPL-001-5 Requirement R4, Parts 4.2.2.1 and 4.2.2.2, including an implementation timetable and annual review of implementation status, should not and do not mandate actual implementation of actions identified as needed to prevent the System from Cascading? For example, do you agree that a capital project is not required to be implemented by Requirement R4, Parts 4.2.2.1 and 4.2.2.2, even if the capital project is the only feasible action available to prevent the System from Cascading when analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column?*

### Project Implementation

Language indirectly mandates implementation of construction of a project. The Requirement (Parts 4.2.2.1 and 4.2.2.2), as written, mandates actual implementation of actions identified as needed to prevent the System from Cascading. Language implies that action must be taken.

This aspect of the standard does not appear to meet the ‘Clear Language’ criteria in NERC’s Standards Quality Review ‘QR’ Checklist because the requirement language as written does not assure that entities will be “able to arrive at a consistent interpretation of the required performance.

Commenters suggest removing 4.2.2.1 and 4.2.2.2 which may remove the interpretation issues of whether a CAP is required. This is a meaningless exercise if a project is not required.

Commenter recommends that the SDT remove the timetable language and change the language similar to Requirement 4, part 4.2.1 to state "an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

There is too much room for interpretation and suggests that a CAP is required.

**SDT Response:**

The SDT agrees and is removing Parts 4.2.2.1 and 4.2.2.2 but a three-phase fault followed by a protection failure is being moved to a P8 planning event.

### Requirement of CAP

Language should be changed to a CAP is required or aligned with other extreme events.

Actions to mitigate protection system single point of failure do not usually incur significant cost. Mitigating single points of failure is the direction from FERC order 754. Changes to this Standard was deemed to be the most effective means to accomplish this objective. If corrective actions (capital projects) are not required by this standard, then the FERC objectives may not be achieved which could lead to additional large scale system events or disturbances and additional FERC orders.

**SDT Response:**
The SDT agrees and is making the 2e-2h a P8 planning event with a CAP requirement.

### Project Implementation

If a capital project is the only feasible action, then it can be interpreted that implementation of the capital project is needed.

It appears that requiring an implementation plan and timetable is similar to a corrective action plan and is being mandated. Until the studies are done, it cannot be determined if any capital projects were included. In general, the utility will determine whether or not to address an issue based on risks and consequences of the event.

**SDT Response:**
The intent of the SDT was to have more analysis for a 2e-2h event as compared to other extreme events. It was not the intent of the SDT to require a CAP. However, due to industry comment and the risk of reliability to the BPS, the SDT has decided to make a three phase fault followed by a protection failure a planning events or P8.

### Requirement of Project Implementation

Requirement 4.2.2 only requires “an evaluation of possible actions designed to prevent the System from Cascading”. Requests that if the occurrence of an extreme event (2e-2h) were projected to cause cascading it should mandate actual implementation of actions identified as needed to prevent the System from Cascading.

**SDT Response:**
The SDT agrees and has put these into a P8 planning event.

### Clarification of Wording

Recommend wording for Parts 4.2.2.1 and 4.2.2.2 be similar to Requirement R3, Part 3.5 related to extreme events for the steady state portion of the Planning Assessment.

Recommend that Parts 4.2.2.1 and 4.2.2.2 be revised as follows:

- 4.2.2.1. List System deficiencies, the associated actions needed to prevent the System from Cascading.
- 4.2.2.2. Be reviewed in subsequent annual Planning Assessments for continued validity.

**SDT Response:**
The intent of the SDT was to have more analysis for a three phase fault followed by a protection failure as compared to other extreme events. It was not the intent of the SDT to require a CAP. Since FERC Order No. 754 resulted in follow-up analysis by the industry and the SPCS and SAMS assessment of additional analysis recommended 3-phase faults be analyzed. Based on the reliability risk, the SDT decided to make the three-phase fault followed by a protection failure a P8 event with no Cascading allowed or a CAP requirement.

### CAPs Limited to Protection System Projects

CAPs should be implemented to prevent Cascading; however, this should be limited to protection system projects.

**SDT Response:**
The SDT should not dictate to the TP or PC what the CAP has to be. The PC and/or TP needs to evaluate the best appropriate project to mitigate the violation.

### Clarification of Wording

Parts 4.2.2, 4.2.2.1, and 4.2.2.2 "should not and do not mandate actual implementation of actions identified as needed to prevent the System from Cascading." In fact, its comparison of the language to the language of those requirements associated with a mandatory CAP indicates that the language and obligations under Parts 4.2.2, 4.2.2.1, and 4.2.2.2 are actually more robust and stringent. This comparison is provided above in Question 1. Commenter does not agree with the inclusion of Parts 4.2.2, 4.2.2.1, and 4.2.2.2. Commenter submits that these requirements together amount to an actual implementation requirement, and that the language is consistent with a required/ mandatory CAP. Irrespective to whether or not a Transmission Planner believes a capital project is required to be implemented by Parts 4.2.2.1 and 4.2.2.2, the compliance will be determined by the language in the standard. If the language in Parts 4.2.2, 4.2.2.1, and 4.2.2.2 are essentially the same as that for a CAP, the requirement is essentially equivalent to CAP.

If Parts 4.2.2, 4.2.2.1, and 4.2.2.2 are not removed as requested above, to clarify the intent stated in this question, Commenter recommends the following revisions to the proposed language for Parts 4.2.2, 4.2.2.1, and 4.2.2.2:

**4.2.2** If the analysis concludes there is Cascading caused by the occurrence of extreme events 2e-2h in the stability column, the TP and/or PC shall:

**4.2.2.1** Document the list of System deficiencies and actions that could be taken to prevent the System from Cascading.

**4.2.2.2** Review the list of System Deficiencies and potential actions to address such System deficiencies in subsequent annual Planning Assessments for continued validity

**SDT Response:**
The intent of the SDT was to have more analysis for a three-phase fault followed by a protection failure as compared to other extreme events. It was not the intent of the SDT to require a CAP. However, the SDT has decided to make a three-phase fault followed by a protection failure P8 planning event and require a CAP. This is because FERC Order No. 754 required a three-phase fault and the resultant SPCS and SAMS report indicated there was a reliability risk to the BPS.

### Q2 Additional Comments

**Additional Comment #1**
Commenter believes that analyzing system performance when subject to "Extreme Events" is meant to provide a sense of where instability and/or Cascading could occur for the PC and/or TP to assess what actions could be developed to mitigate or reduce the potential impact. Such actions generally involve positioning the BES, adjusting outage plans, implementing operations strategies, developing a safe posture and preparing for resiliency plans, but not any capital investment projects. Note that this does not preclude the responsible entity from implementing any of these actions in its sole discretion, but it should not be mandated. Capital projects to address operational circumstances should not be mandated in a TPL standard. Further, requiring capital projects would exceed the scope of FERC Order 754 and 786 as well as the SAR.

**SDT Response:**
Per the NERC Glossary definition of CAP, a capital project is not required if implementing operations strategies mitigate the performance violation. The language in Parts 4.2.2.1 and 4.2.2.2 was intended to include operational strategies not just capital projects. However, the SDT decided to remove 4.2.2.1 and 4.2.2.2 and make a three phase fault followed by a protection failure a P8 planning event.

**Additional Comment #2**
Recommend the drafting team adds language to section 4.2.2.2 to clarify during the review process pertaining to the Planning Assessments for continued validity and implementation status that an adjustable time frame would always be taken into consideration.

**SDT Response:**
The SDT removed Part 4.2.2.2 and is making the three-phase fault followed by a protection failure a P8 planning event. The SDT also developed an implementation plan for TPL-001-5.

**Additional Comment #3**
Oftentimes the capital project may be a relay upgrade project which is relatively low cost compared to the benefits.

**SDT Response:**
The SDT agrees.

## Question 3: Associated Timetable and Annual Review Requirement R4 Summary Response

*3. Do you agree with the omission, as proposed in TPL-001-5 Requirement R4, Part 4.2, of a requirement similar to that of Requirement R2, Part 2.7, which states that the planned System shall continue to meet the performance requirements in Table 1 in subsequent Planning Assessments?*

### Requirement Omission

Commenter believes that the omission in 4.2 is necessary as there are not performance requirements in the Table for Extreme Events.

Commenter agrees that a requirement to ensure that Cascading does not occur in subsequent Planning Assessment given extreme events 2e-2h in the stability column should be omitted

**SDT Response:**

The SDT appreciates these comments. However, due to other comments received by the industry and since FERC Order No. 754 required a three-phase fault and the resultant SPCS and SAMS report indicated there was a reliability risk to the BPS, the SDT has decided to require a CAP for a three-phase fault followed by a protection failure results in Cascading or instability. This has been also made into a P8 event.

### Implementation Timetable

Commenter disagrees with adding the 4.2.2.1 requirement to list a timetable for implementation of actions to reduce the likelihood or mitigate the consequences of any extreme contingence events, including extreme events 2e-2h and the 4.2.2.2 requirement to continue to review the validity and implementation status of the possible actions.

**SDT Response:**

The SDT appreciates these comments. However, due to the following:

- other comments received by the industry
- because FERC Order No. 754 required a three-phase fault and the resultant SPCS and SAMS report indicated there was a reliability risk to the BPS

The SDT has decided to require a CAP for a three-phase fault followed by a protection failure.

### System Performance

Commenter believes that requirement 2.7 would cover system performance for the R4 requirements.

The planned system should always meet the performance requirements in Table 1 in any Planning Assessment that is performed. To the extent a Corrective Action Plan is developed for issues identified in one Planning Assessment and the issues go away in subsequent Planning Assessments due to changes in load forecasts or other drives of the original issue, elimination or modification of the Corrective Action Plan in the subsequent Planning Assessment should certainly be allowed, but the language above that states "the planned System shall continue to meet the performance requirements in Table 1 in subsequent Planning Assessments" seems unnecessary since the Table 1 requirements apply to all Planning Assessments.

If a system risk or vulnerability has been identified as a result of conducting a mandatory reliability assessment, Corrective Action Plan(s) must be developed which maintains system performance. Customers and regulators will not accept that a system deficiency was identified but not mitigated by a Transmission Planner when such an event occurs. If maintaining system performance following an event is not required, then performing an assessment of that event should not be required.

**SDT Response:**
The SDT agrees and has removed the confusion by making the three-phase fault followed by a protection failure a P8 planning event requiring a CAP to meet the associated performance requirements with Implementation Plan.

## Q3 Additional Comments

### Additional Comment #1
CAPs should not be required for a three-phase fault followed by a protection failure.

Commenter agrees that a corrective action plan should not be required for an extreme event. The 2e through 2h events referenced in Requirement R4, Part 4.2.2, however, should be planning events and, accordingly, corrective action plans should be required for them.

**SDT Response:**
The SDT disagrees, this is due to the fact that FERC Order No. 754 required a three-phase fault and the resultant SPCS and SAMS report indicated there was a reliability risk to the BPS. This is also supported by other industry comments. The SDT has decided to make a three-phase fault followed by a protection failure a P8 planning event.

### Additional Comment #2
Commenter agrees that extreme events do not need the same level of requirements as Planning Events.

**SDT Response:**
The SDT disagrees, this is due to the fact that FERC Order No. 754 required a three-phase fault and the resultant SPCS and SAMS report indicated there was a reliability risk to the BPS. This is also supported by other industry comments. The SDT has decided to make a three-phase fault followed by a protection failure a P8 planning event.

### Additional Comment #3
As mentioned in our response to Q2, our interpretation of Part 4.2.2 is that it requires the

implementation of corrective action plans –including capital projects– when analysis concludes there is Cascading. We support the implementation of corrective action plans.

If the drafting team considers that this is not the intent of the revision, and the implementation of capital projects IS NOT required, we propose that Part 4.2.2 be revised to make this clear.

**SDT Response:**
The SDT agrees and decided to make a three-phase fault followed by a protection failure a P8 planning event which removed much of the confusion in the industry.

## Question 4: Footnote 13
## Summary Response

*4. Do you agree with including Table 1 Footnote 13 a., "[a] single protective relay which responds to electrical quantities, without an alternative that provides comparable Normal Clearing times, e.g., sudden pressure relaying", and its limitation to only the specific single protective relay and not to other elements of the associated Protection System?*

The SDT paid considerable attention to the depth of the industry comments received regarding Footnote 13 (Questions 3, 4, and 5) and has sought to address general and specific industry comments with the following response. The most common comment noted the discrepancy between red-line version and clean version of the proposed draft; the SDT agrees and has corrected the Footnote 13 bullets to "a,b,c,d", not "1,2,3,4". One theme that was communicated by industry was to desire specificity about the Protection System components that must be redundant. The SDT seeks to make clear that the draft Footnote 13, as well as changes to the P5 and extreme events, do not prescribe any level of redundancy. Footnote 13 is not a definition of redundancy. On the contrary, Footnote 13 identifies the components of a Protection System that should be considered for redundancy and failures that may lead to Delayed Clearing, when Planning Coordinators and Transmission Planners simulate Contingencies for the purpose of analysis that supports TPL-001-5 annual Planning Assessments.

### Sudden Pressure Relaying
Several stakeholders suggested removing "e.g. sudden pressure relaying" from Footnote 13a. It was suggested that this confusing language can appear to identify sudden pressure relays as a type of protective relays to be evaluated.

**SDT Response:** The SDT agrees that specific reference to sudden pressure relaying confuses the purpose of Footnote 13a, which is to focus on an alternative that provides comparable Normal Clearing times to a single protective relay which responds to electrical quantities. The proposed draft has been revised to omit this language.

### Single Protective Relay Action
Similar to the comments suggesting that the SDT should define redundancy, some industry commenters suggested that the SDT should specify the actions taken by a single protective relay, instead of identifying

individual Protection System components when considering for redundancy under this standard. Relatedly, it was suggested that reference to a single protective relay should apply to a relay unit and not a relay element (multiple relay elements within a single relay unit are not redundant given a common failure, e.g., power supply).

**SDT Response:** The Footnote 13a in the proposed TPL-001-5 standard specifies the non-redundant components of a Protection System that the Planning Coordinator and Transmission Planner must consider. Therefore the PC and TP must determine how to properly simulate failures of non-redundant components of a Protection System, given the consideration of their constituent Protection Systems. The SDT does not desire to propose language that is overly prescriptive and instead desires that the focus remain on failures of non-redundant components of a Protection System that must be simulated for Delayed Fault Clearing.

## Question 5: Footnote 13
## Summary Response

*5. Do you agree with the inclusion of Table 1 Footnote 13 b. & c. stipulation, "which is not monitored or not reported", and that it conveys the expectation that the monitoring and reporting is sufficient to result in prompt remediation addressing the failure status of the associated equipment?*

### Defining "Monitored" and "Reported"

The most-frequently provided industry comment to Question 5 indicated that "monitored" and "reported" were not sufficiently defined, such as in PRC-005-6 Tables 1-2, 1-4, and 2. Specifically, a desire was expressed for a reporting time stipulation when considering redundancy and how quickly corrective action could be enacted.

**SDT Response:** The SDT agrees with the industry comments and has modified the proposed Footnote 13b and 13c to language similar to that in the Standards Authorization Request (SAR) proposed following the joint SAMS/SPCS report: "not monitored such that alarms are centrally reported (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated)." The SDT simplified the suggested language to "not monitored or not reported at a Control Center." It is well understood that a Control Center hosts operating personnel that monitor the Bulk Electric System (BES) in real-time to perform reliability tasks, so the SDT did not believe specifying a reporting or correction initiation timeframe was necessary. Separately, reference to a single station dc supply was added by the SDT to 13c to align with the Protection System defined term.

### Communication Systems

Some industry commenters suggested that communication systems referenced by Footnote 13b should be limited to just those used for critical/crucial Normal Clearing times.

**SDT Response:** Given the increasing importance of communication-aided Protection Systems (e.g., pilot protection schemes, direct transfer tripping schemes, permissive transfer tripping schemes, etc.), the proper operation of the communication system must be considered when considering potential single point of failure (SPF) components of Protection Systems. Although the SAMS/SPCS report noted that a SPF in a communication system posed a lower level of risk, the drafting team augmented the SAMS/SPCS recommendations to include reference to the subset of communication systems that are part of a communication-aided Protection System, necessary where the performance of that Protection System is required to achieve Transmission System Planning Performance Requirements, enumerated in Table 1 of TPL-001-5. In other words, a communication-aided Protection System that may experience a SPF, causing it to operate improperly or not at all leading to Delayed Clearing, must be considered as part of non-redundancy. The SDT concluded that the failure of communication-aided Protection Systems may take many forms; however, by alarming and monitoring these systems, the overall risk of impact to the BES is reduced to an acceptable level. Most new Protection Systems deployed in the industry include communication-aided protection with component and communication failure alarms monitored at centralized Control Centers. This alarm monitoring is similar to the requirement associated with station DC supplies. Therefore, this requirement is more applicable to legacy systems that need communication-aided Protection Systems to meet performance requirements of the TPL-001-5 standard. Further, the SDT does not believe that critical or crucial clearing times are pertinent to the Planning Coordinator or Transmission Planner when determining how long to simulate a fault until it clears. In other words, the critical clearing time is a result of analysis, not a precondition of the analysis (such as considerations of Protection System component redundancy).

### Protective Functions

For consistency amongst the non-redundant components of a Protection System that must be considered as part of Footnote 13, the protective functions associated with a single dc supply should refer to Normal Clearing.

**SDT Response:** The SDT agrees with the industry comment and has added reference to Normal Clearing to Footnote 13c and 13d for consistency and clarity.

### Q5 Additional Comments

### Additional Comment #1

Some industry stakeholders believe that preventive maintenance per PRC-005 provides reasonable and sufficient assurance for detection and handling “open circuit” conditions, implying that this stipulation in Footnote 13c should be omitted.

**SDT Response:** The SDT agrees that PRC-005 establishes maintenance practices that may significantly reduce the likelihood of a single point of failure in a dc supply serving protective functions, however this may not eliminate its occurrence and may lead to Delayed Fault Clearing. The SDT proposed Footnote 13c is consistent with the SAMS/SPCS report recommendations and the Project 2015-10 SAR.

## Question 6: Footnote 13
## Summary Response

*6. Do you agree with the inclusion of Table 1 Footnote 13 d., and that it, in conjunction with defined terms, identifies what constitutes all of the elements of, "A single control circuitry associated with protective functions including the trip coil(s) of the circuit breakers or other interrupting devices."?*

### Definition of Control Circuitry

The most common industry comments regarding Footnote 13d suggested the definitions of control circuitry remains vague; that the demarcation of supply and control circuitry was vague; and, suggested aligning the Footnote 13d language closer to that recommended in the SPCS report.

**SDT Response:** The SDT intended single DC supply to refer to the entire set of equipment that comprises the DC source supplying power to Protection System components necessary for Normal Clearing. In other words, the SDT sought to specify that, within the entire set of equipment comprising the single DC supply, a failure of a piece of equipment that causes the single DC supply to be unable to source power to the protective functions necessary for Normal Clearing must be considered as part of Footnote 13. Relatedly, the SDT agrees that a typical station battery bank is only one part of the single DC supply. Further, a failure of a station battery may be masked for short time by the AC-sourced station battery charger. However, the SDT did not prescribe specific DC supply design configurations. Instead, the SDT emphasized that the single DC supply must be considered for susceptibility to SPF as part of Footnote 13. To clarify Footnote 13d, the SDT has revised it to explicitly include auxiliary relays and lockout relays in the control circuitry, as well as specify the circuitry components to consider extends through and including the trip coils.

### Trip Coil Failure

Some industry commenters suggested that a failure in a non-redundant single trip coil that results in a breaker not acting properly is covered by breaker failure (P4 events). Similarly, it was suggested to replace references to interrupting device trip coils with reference to auxiliary relays in the interrupting device control circuity given that this is more severe and simulation of a single interrupting device trip coil failure is expected to be the same as the simulation of a P4.

**SDT Response:** While trip coil monitoring devices are commonly available to give awareness of potential trip coil failure, the SDT believes monitoring trip coil failure or relay trouble indication is insufficient to ensure that a SPF is not present within a single control circuit. Similarly, DC undervoltage relaying or other control circuit continuity monitoring may indicate a problem with part of the DC control circuit, but may not give awareness of SPF risks such as serial tripping devices (ANSI #86 and #94 devices). Therefore, The SDT did not incorporate a monitoring provision into Footnote 13d and intends for non-redundant components within the DC control circuitry of a Protection System to be considered as part of Footnote 13.

## Question 7: Known Outages
## Summary Response

*7. Do you agree with the proposed changes to Requirement 1, Part 1.1.2 that modify which known outages shall be represented in System models from those "with a duration of at least six months" to those* *selected by the Planning Coordinator (PC)/Transmission Planner (TP) "in consultation with" their Reliability Coordinators (RCs)?*

### Selecting Outages in Consultation with Reliability Coordinator

The majority of industry respondents commented that selecting outages in consultation with their Reliability Coordinators was problematic and offered alternative suggestions.

**SDT Response:** The range of industry comments to this question indicate there are substantial regional differences in the methods and procedures to address outages in the Near-Term Transmission Planning Horizon. Accordingly the SDT has revised Requirement 1, Part 1.1.2 to recognize and codify the various means that TPs and PCs currently employ to consider the impact of know maintenance outages in the near term planning horizon.

### Roles and Responsibilities for Reliability Coordinator and Transmission Planner

Several industry respondents commented that if the coordination language is retained clarity needs to be added to better define "consultation". The roles and responsibilities need to be spelled out including establishing criteria for outages and resolving conflicts between the RC and TP.

**SDT Response:** The range of industry comments to this question indicate there are substantial regional differences in the methods and procedures to address outages in the Near-Term Transmission Planning Horizon. Accordingly the SDT has revised Requirement 1, Part 1.1.2 to recognize and codify the various means that TPs and PCs currently employ to consider the impact of know maintenance outages in the near term planning horizon.

### Outages in the Near Term Planning Horizon

Several industry commenters believed that outages in the near term planning horizon should remain within the auspicious of the TPL standard and not in the IRO arena.

**SDT Response:** The range of industry comments to this question indicate there are substantial regional differences in the methods and procedures to address outages in the Near-Term Transmission Planning Horizon. Accordingly the SDT has revised Requirement 1, Part 1.1.2 to recognize and codify the various means that TPs and PCs currently employ to consider the impact of know maintenance outages in the near term planning horizon.

### IRO-017

Several industry commenters believed IRO-017 should be the primary vehicle to include planned outages in the near term planning horizon.

**SDT Response:** The range of industry comments to this question indicate there are substantial regional differences in the methods and procedures to address outages in the Near-Term Transmission Planning Horizon. Accordingly the SDT has revised Requirement 1, Part 1.1.2 to recognize and codify the various means that TPs and PCs currently employ to consider the impact of know maintenance outages in the near term planning horizon.

### Six Month Outage Duration

Several industry commenters suggested the directive could be addressed by changing the 6 month outage period to something like "outages spanning the entire season under study" (or other outages as determined by the TP/PC)

**SDT Response:** The SDT believes that the time duration of a known outage does not necessarily correlate with the significance of outage. The range of industry comments to this question indicate there are substantial regional differences in the methods and procedures to address outages in the Near Term Transmission Planning Horizon. Accordingly the SDT has revised Requirement 1 part 1.1.2 to recognize and codify the various means that TPs and PCs currently employ to consider the impact of know maintenance outages in the near term planning horizon.

### Q7 Additional Comments

#### Additional Comment #1

Several commenters requested event clarification – standard specifies that only P1 events should be run on the cases with these outages in place, do we remove them for the other studies

**SDT Response:** Requirement R2, Part 2.4.3 requires new maintenance outages that have met the TP/PC requirement for studies to be conducted for P1 events only. How, or if, an entity choses to incorporate outages when performing additional analysis is not a NERC TPL standard requirement.

#### Additional Comments #2

One commenter responded with a minor changes Lower-case the term "Off Peak".

**SDT Response:** The capitalized term "Off-Peak" are in Parts 2.1.3 and 2.4.3 that have already been approved by industry. The SDT is not proposing to change those requirements.

## Question 8: Applicability
## Summary Response

*8. Do you agree with omitting the Reliability Coordinator (RC) from the applicability of the TPL-001-5 standard given that Requirement R1, Part1.1.2 requires consultation between the TP/PC and the RC to determine which known outages to select for representation in System models?*

### Regional Differences

The range of industry comments to question 7 indicates there are substantial regional differences in the methods and procedures to address outages in the near term planning horizon. The majority of industry respondents commented that Reliability Coordinator involvement is not necessary (this standard only applies to TP and PCs) or move RC duty details to IRO-017 (then delete from TPL).

**SDT Response:** The range of industry comments to this question indicate there are substantial regional differences in the methods and procedures to address outages in the Near-Term Transmission Planning Horizon. Accordingly the SDT has revised Requirement 1, Part 1.1.2 to recognize and codify the various means that TPs and PCs currently employ to consider the impact of know maintenance outages in the near term planning horizon.

### Reliability Coordinator Applicability

The range of industry comments to question 7 indicates there are substantial regional differences in the methods and procedures to address outages in the near term planning horizon. The significant minority of industry respondents commented that if "consultation" with RC is not removed, then add the RC to the applicability portion.

**SDT Response:** The range of industry comments to this question indicate there are substantial regional differences in the methods and procedures to address outages in the Near-Term Transmission Planning Horizon. Accordingly the SDT has revised Requirement 1, Part 1.1.2 to recognize and codify the various means that TPs and PCs currently employ to consider the impact of know maintenance outages in the near term planning horizon.

### Q8 Additional Comments

Several comments that were duplicative of comments received in question 7 including-Specify roles and responsibilities; Revise IRO-017-1 to address FERC directive; and Move the reporting requirement in IRO-017-1 R3 to TPL-001-5 instead.

**SDT Response**: The range of industry comments to this question indicate there are substantial regional differences in the methods and procedures to address outages in the Near-Term Transmission Planning Horizon. Accordingly the SDT has revised Requirement 1, Part 1.1.2 to recognize and codify the various means that TPs and PCs currently employ to consider the impact of know maintenance outages in the near term planning horizon. Modifications to IRO-017 are not within the scope of the approved Project 2015-10 SAR.

## Question 9: Outage Coordination
## Summary Response

*9. FERC Order No. 786 Paragraphs 40-45 direct modification to address significant planned maintenance outages with durations less than 6 months in planning assessments. Are you aware of an existing standard/requirement, consistent with industry practice and applicability that requires review and coordination of significant known maintenance outages less than 6 months in duration for inclusion in System models (TPL 001-4 Requirement R1 Part R1.1.2)?*

### Regional Differences Concerning Outage Coordination (IRO-017)

The range of industry comments to question 7 and 9 indicates there are substantial regional differences in the methods and procedures to address outages in the near term planning horizon. The majority of industry respondents pointed to IRO-017 to tighten up coordination of significant outages that are less than 6-month duration; expressed that coordination is already being done through various mechanism; or the directive predates IRO-017-1 and isn't relevant anymore.

**SDT Response:** The range of industry comments to this question indicate there are substantial regional differences in the methods and procedures to address outages in the Near-Term Transmission Planning Horizon. Accordingly the SDT has revised Requirement 1, Part 1.1.2 to recognize and codify the various means that TPs and PCs currently employ to consider the impact of know maintenance outages in the near term planning horizon. Modifications to IRO-017 are not within the scope of the approved Project 2015-10 SAR.

### Regional Differences Concerning Outage Coordination (MOD-032) and Applicability of Transmission Owner and Generator Owner

The range of industry comments to question 7 and 9 indicates there are substantial regional differences in the methods and procedures to address outages in the near term planning horizon. Several industry respondents suggested to modify MOD-032 such that known outages are included in the data submitted for TPL.

**SDT Response:** The range of industry comments to this question indicate there are substantial regional differences in the methods and procedures to address outages in the Near-Term Transmission Planning Horizon. Accordingly the SDT has revised Requirement 1, Part 1.1.2 to recognize and codify the various means that TPs and PCs currently employ to consider the impact of known maintenance outages in the near term planning horizon. MOD-032 does not specifically address how outages are communicated, however the TP and PC may require Transmission Owner (TO) and Generator (GO) to provide outage related data.

## Question 10: Implementation Plan
## Summary Response

*10. Do you agree with the 36 month implementation period to address all Requirements except for Requirement R4, Part 4.2, and Requirement 2, Part 2.7 associated with the modified P5 events further defined in the redline changes to Footnote 13.*

### Existing substations and new substations

There is a suggestion to grandfather existing substations and any new requirements would apply to new substations when they are built.

**SDT Response:** FERC Order No. 754 analysis and the resultant SPCS and SAMS report indicated there is a reliability risk to the BPS caused by single point of failures with existing Protection Systems. These reliability concerns need to be addressed for the existing and planned Protection Systems. The purpose of the Implementation Plan is to allow for identification and mitigation of all Protection System single points of failures to meet performance requirements, whether existing or planned.

### Proposed P5 event / footnote 13

Some commenters disagree with a 36 month implementation period because of the ambiguity in the proposed P5 event / footnote 13. Additionally, larger utilities suggested the Implementation Plan be extended to 48 month.

**SDT Response:** The SDT has addressed ambiguity concerns in Footnote 13 language previously in Questions 4 through 6 and has modified Footnote 13. The SDT feels that 36 months are adequate to complete first set of studies. The implantation plan allows for additional time to develop a CAP.

### Stability Analysis for Spare Equipment

Addressing all new requirements except 4.2 and 2.7 which would include the stability analysis for spare equipment and developing a process for selecting known outages and establishing coordination with protection engineers. Stability analysis is the most time consuming part of the planning assessments.

**SDT Response:** The SDT agrees and has revised the implementation.

## Question 11: Implementation Plan Summary Response

*11.Do you agree with the 60 month implementation plan for Requirement 4, Part 4.2 and Requirement 2, Part 2.7 associated with the modified P5 events further defined in the redline changes to Footnote 13.?*

### The Additional 24-months Too Short

The additional 24-months to implement any resulting Corrective Action Plans for P5 events may be too short.

**SDT Response:** The additional 24 months is to only identify appropriate Corrective Action Plan and establish the associated timetables for completion.

### 72-months Implementation Recommended

A 72-month implementation plan would be preferable for the development of Corrective Action Plans to address newly-added studies involving single point of failure on Protection Systems.

**SDT Response:** The SDT disagrees. The revised implementation period provides Planning Coordinators and Transmission Planners with 36 months to update their annual Planning Assessments to include the new System models and studies required by the standard. In addition, the implementation plan includes an additional 24-month period for the development of Corrective Action Plans under TPL-001-5 to address newly added studies involving single points of failure on Protection Systems. Furthermore, in the event that an Operating Procedure, Non-Consequential Load Loss or curtailment of Firm Transmission Service is insufficient to meet performance requirements, the implementation plan includes an additional 36 months to meet the performance requirements of Table 1 for revisions to P5, and the addition of P8.

## Question 12: Cost Effectiveness Summary Response

*12. In looking at all proposed recommendations from the standard drafting team, are the proposed changes a cost effective approach which meets the FERC directives? (see Cost Effectiveness Background Document)*

**CAP for Extreme Events Low Probability Event not economical:**
Several industry comments indicate that proposed TPL-001-5 Requirement R4, Parts 4.2.2.1 and 4.2.2.2, including an implementation timetable and annual review of implementation status for the extreme stability 2e-2h event contingencies go significantly beyond obligations for all other extreme events, and it is not economically justifiable and cost effective to require a CAP for low probability events.

**SDT Response:** FERC Order No. 754 resulted in follow-up analysis by the industry and the SPCS and SAMS assessment of additional analysis recommended three-phase faults be analyzed. Based on the reliability risk, the SDT decided to make the three-phase fault followed by a protection failure a P8 event with no cascading allowed. In view of the addition of P8 events, industry stakeholders will have the opportunity to re-evaluated cost effectiveness in the next posting.

**Six Month Outage Duration review**
Several industry comments indicate that Transmission Planners (TP) performing an annual study review of outages less than six months have redundancies associated with outage coordination and does not represent a cost effective approach.

**SDT Response: T**he SDT has revised Requirement 1, Part 1.1.2 to recognize and codify the various means that TPs and PCs currently employ to consider the impact of known maintenance outages in the near term planning horizon. Industry stakeholders will have the opportunity to re-evaluate cost effectiveness in the next posting.

**Q12 Additional Comment**
Requiring a fully-redundant control circuitry without due consideration of status monitoring combined with periodic independent component testing is duplicative for system reliability and is not the most cost-effective option to address the FERC directive. The cost-effective solution is to include the allowance for excluding control circuitry with monitoring from Footnote 13d.

**SDT Response:** The SDT disagrees with the comment because continuity monitoring of the control circuits may not give awareness of single point of failure risks. Therefore, the SDT did not incorporate a monitoring provision into Footnote 13d and intends for non-redundant components within the control circuitry of a Protection System to be considered as part of Footnote 13d. Please refer to Question 6 response.

## Question 13: Governing Documents Summary Response

*13. Are you aware of any other governing documents that could be in conflict with the current proposal for this draft of the standard?*

### Coordination between the TPL-001-5 and the new FAC-015 standards

The industry consider that the new FAC-015 requirements with respect to the system operating limits should be used in planning assessments and need to be included within TPL-001-5.

**SDT Response:** The new FAC-015 requirements with respect to the system operating limits to be used in planning assessments cannot be included within TPL-001-5 because these are not part of the objectives of the Project 2015-10 Single Point of Failure SAR. The request to coordinate the standards FAC-015 and TPL-001 with respect to the system operating limits to be used in planning assessments belong in a new SAR and must be addressed to NERC.

### Multiple NERC definitions of acceptable types of redundancy of Protection System

The difference between the protection system redundancy definition in the 2009 NERC document "Protection System Reliability – Redundancy of Protection", as well as the redundancy requirements described in PRC-012-2, and theTPL-001-5 footnote 13 will likely cause confusion in industry.

**SDT Response:** There is a difference between the Protection System redundancy definition in the documents mentioned above and footnote 13 of TPL-001-5. The purpose of the TPL-001 modified footnote 13 is to specify which non-redundant components of a Protection System to be considered for the Single Point of Failure analysis. It was not intended to define the Protection System redundancy. The inclusion of some elements of a protection system but not all, aligns with the SAMS and SPCS recommendations.

### Disconnection between operations and planning

The IRO-017 already defines the process for studying outages within the Operational Planning Horizon. The industries consider that the maintenance outages should be evaluated in the Operating Horizon, if not, a conflict can be created between the two standards TPL-001-5 and IRO-017-1.

**SDT Response:** The planned outages studied in TPL-001 are provided to the RC through the Near-Term Planning Assessment to jointly develop solutions for identified issues or conflicts with planned outages as part of the outage coordination process of IRO-017. Therefore, there is no conflict between TPL-001 and IRO-017.

### Implementation of corrective actions might require capital projects and additional infrastructure

Requiring implementation of corrective actions which include capital projects and additional infrastructure would contradict the Energy Policy Act of 2005 and directly conflicts with some provincial regulations.

**SDT Response:** Reliable operation of the BPS is required by the Federal Legislation. Requirement 2.7.1 allows solutions to be developed which don't necessarily require construction of additional generation or transmission capacity. The SDT proposes to add a new P8 Planning Event to "Table 1 – Steady State and Stability Performance Planning Events", in order to include a 3-phase fault and failure of a non-redundant component of a Protection System.

## Question 14: Other Considerations
## Summary Response

*14. Do you have any other general recommendations/considerations for the drafting team?*

**Paragraph 81**

Requirements R5, R6, R7, and R8 fall under such criteria

**SDT Response:** The SDT disagrees that Requirement 5, 6, 7,-8 meet the Paragraph 81 criteria.

**NERC Project to address FERC Directives**

Commenter suggests that objectives outlined in the FERC Directives could be accomplished without the need to revise the standard in this manner. The objectives could be met in the form of a NERC project or initiative requesting that these assessments/studies be done in 10% or 20% intervals over a set period of time, and the data submitted to NERC for its review. We feel that requiring these objectives in a standard, with the ever changing configuration of the system, would require that this work as proposed be done every year, which would be extremely burdensome. We recommend that the studies and assessments that will be required would be better suited outside of the NERC standards.

**SDT Response:** Thank you for your comment. A standards project was required to address the FERC directives.

**TPL-001-5 R4, Part 4.2.2.2 including extreme event 2e-2h**

Many of the comments submitted for Question 14 paralleled or echoed the comments from Questions 1-3. Additionally commenters proposed specific language suggestions for certain sections.

**SDT Response:** When possible the SDT considered the language suggestions. Please see the revised standard to see if your specific suggestion or a close proximity was incorporated into the new language. For the comments that were submitted in Question 14 that paralleled or echoed the comments from Questions 1-3, please see the comments from the SDT provided in Questions 1-3.

**Economic Impacts of Extreme Events**

Commenter suggested the drafting team should revisit the economic impacts of the proposed changes, specifically those concerning extreme events.

**SDT Response:** See response for Question 12.

**TPL-001-5 Footnote 13**

Many of the comments submitted for Question 14 paralleled or echoed the comments from Questions 4-6. Additionally commenters proposed specific language suggestions for certain sections.

**SDT Response:** When possible, the SDT considered the language suggestions. Please see the revised standard to see if your specific suggestion or a close proximity was incorporated into the new language.

For the comments that were submitted in Question 14 that paralleled or echoed the comments from Questions 4-6, please see the comments from the SDT provided in Questions 4-6.

### TPL-001-5 TP/PC Coordination with RC, Outage Coordination

Many of the comments submitted for Question 14 paralleled or echoed the comments from Questions 7-9. Additionally commenters proposed moving requirements both to and from IRO-017. Several stakeholders expressed concerns that selecting outages in consultation with their Reliability Coordinators was problematic and offered alternative suggestions.

**SDT Response:** The range of industry comments to this question indicate there are substantial regional differences in the methods and procedures to address outages in the near term planning horizon. Those differences contribute to a legitimate difficulty in designing a cost-effective continent wide standard addressing the FERC directive. For the comments that were submitted in Question 14 that paralleled or echoed the comments from Questions 7-9, please see the comments from the SDT provided in Questions 7-9.

### Spare Equipment Strategy in Stability Study

The new version of the standard has included the spare equipment strategy into the stability portion of the assessment. This is unnecessary because this analysis is captured in the normal stability study. For example, a transformer qualifies as equipment with lead time greater than a year. The loss of the transformer is captured in the normal stability contingency analysis. If this analysis resulted in an unacceptable response, the scenario would be investigated to determine a mitigation (like using a spare transformer in its place).

**SDT Response:** The existing language in the standard requires a CAP. Loss of long-lead items are studied. No changes to the language is necessary.

### Monitoring of Protection System

If monitoring of Protection System components is counted for purposes of TPL-001-5, is it the drafting team's intent that an entity would be obligated to maintain the alarming paths and monitoring systems under PRC-005-6 (Requirement R1, Part 1.2, and Table 2)? An entity should be allowed to consider monitoring for purposes of TPL-001-5 but treat the associated Protection System component(s) as unmonitored for purposes of PRC-005-6.

**SDT Response:** See response to Question 6.

### Spare Equipment Strategy

The proposed changes to the Spare Equipment Strategy paragraph (2.4.5) create an unclear requirement for determining if acceptable performance has been met. The revised language introduces a "more severe System impact" standard of performance. This begs the question, "More severe than what?

**SDT Response:** This exists in the current of the standard and it is up to the PC and TP to determine what is more severe.

### Linking Standards

Perhaps this is an opportunity to link TPL-001-5 and PRC-023-4 into a single assessment?

**SDT Response:** the TP and PC can take the Planning Assessment and apply to PRC-023-4. No link is required

### Models Developed under MOD-032

The timing of models developed under MOD-032 sometime make it difficult to have an exact “year five” model. R2.1.1 could be more flexible – similar to 2.1.2.

**SDT Response:** The TP and PC can request data for any year that they need.

### Standard Revision

In section 2.4., the last sentence should be adjusted to look more like the last sentence of section 2.2.

**SDT Response:** Thank you for your comment. This is not in the scope of the SAR.
NERC Glossary of Terms

### Footnote 12

Regarding Table 1, if the performance requirements (steady state / stability) are not being met, AND, if Table 1 indicates that non-consequential load loss and interruption of Firm Transmission Service are allowed, is a specific corrective action plan required as per Requirement 2.7 (assuming that non-consequential load loss and/or interruption of Firm Transmission Service would allow for meeting the performance requirements)? This question relates to a scenario where Footnote 12 does not apply. A general recommendation is to clarify within the standard whether or not a specific corrective action plan is required to be documented, as per Requirement 2.7, in the Planning Assessment for this scenario (i.e. performance requirements are not being met and Footnote 12 does not apply).

**SDT Response:** Thank you for your comment. This is not in the scope of the SAR.

### Revision of PRC Standard

An alternative first step should have been in a PRC Standard to address the concerns in reference to Single Point Failure. Furthermore, there could be a potential disconnect between the Transmission Planner and Protection Engineers by placing this only in a Planning Standard. Also, we recommend that the draft team includes the Transmission Owner (TO) and Generator Owner (GO) in the applicability section, along with an additional requirement specifying that the TO and GO should provide pertinent data (e.g., contingency definitions, elements tripped) upon request by the PC in order to assess the impact of Single Point of Failure in their assessments.

**SDT Response:** Thank you for your comment. This is not in the scope of the SAR.

## Industry Segments

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities