# Comment Report

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| **Project Name:** | Project 2015-10 Single Points of Failure \| TPL-001-5 |
| Comment Period Start Date: | 2/26/2018 |
| Comment Period End Date: | 4/23/2018 |
| Associated Ballots: | 2015-10 Single Points of Failure TPL-001-5 AB 2 ST<br>2015-10 Single Points of Failure TPL-001-5 Implementation Plan IN 1 ST |

There were 70 sets of responses, including comments from approximately 190 different people from approximately 117 companies representing 10 of the Industry Segments as shown in the table on the following pages.

**Questions**

**1. Do you agree with the creation of the proposed P8 event?**

**2. Do you agree with the changes to TPL-001-4 Requirement 1, Part 1.1.2, in order to meet the FERC directive in Order No. 786?**

**3. Do you agree with the proposed implementation plan?**

**4. Do you agree with the proposed revisions to TPL-001-4?**

**5. Are the proposed revisions to TPL-001-4 along with the Implementation Plan a cost effective way of meeting the FERC directives in Order No. 786 and Order No. 754?**

| Organization Name | Name | Segment(s) | Region | Group Name | Group Member Name | Group Member Organization | Group Member Segment(s) | Group Member Region |
|---|---|---|---|---|---|---|---|---|
| Brandon McCormick | Brandon McCormick | | FRCC | FMPA | Tim Beyrle | City of New Smyrna Beach Utilities Commission | 4 | FRCC |
| | | | | | Jim Howard | Lakeland Electric | 5 | FRCC |
| | | | | | Lynne Mila | City of Clewiston | 4 | FRCC |
| | | | | | Javier Cisneros | Fort Pierce Utilities Authority | 3 | FRCC |
| | | | | | Randy Hahn | Ocala Utility Services | 3 | FRCC |
| | | | | | Don Cuevas | Beaches Energy Services | 1 | FRCC |
| | | | | | Jeffrey Partington | Keys Energy Services | 4 | FRCC |
| | | | | | Tom Reedy | Florida Municipal Power Pool | 6 | FRCC |
| | | | | | Steven Lancaster | Beaches Energy Services | 3 | FRCC |
| | | | | | Mike Blough | Kissimmee Utility Authority | 5 | FRCC |
| | | | | | Chris Adkins | City of Leesburg | 3 | FRCC |
| | | | | | Ginny Beigel | City of Vero Beach | 3 | FRCC |
| ACES Power Marketing | Brian Van Gheem | 6 | NA - Not Applicable | ACES Standards Collaborators | Greg Froehling | Rayburn Country Electric Cooperative, Inc. | 3 | SPP RE |
| | | | | | Paul Henderson | Hoosier Energy Rural Electric Cooperative, Inc. | 1 | RF |

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|---|---|---|---|---|---|---|---|---|
| | | | | | Ginger Mercier | Prairie Power, Inc. | 1,3 | SERC |
| | | | | | Tara Lightner | Sunflower Electric Power Corporation | 1 | SPP RE |
| | | | | | Shari Heino | Brazos Electric Power Cooperative, Inc. | 1,5 | Texas RE |
| | | | | | John Shaver | Arizona Electric Power Cooperative, Inc. | 1 | WECC |
| | | | | | Michael Brytowski | Great River Energy | 1,3,5,6 | MRO |
| Exelon | Chris Scanlon | 1 | | Exelon Utilities | Chris Scanlon | BGE, ComEd, PECO TO's | 1 | RF |
| | | | | | John Bee | BGE, ComEd, PECO LSE's | 3 | RF |
| Tennessee Valley Authority | Dennis Chastain | 1,3,5,6 | SERC | Tennessee Valley Authority | DeWayne Scott | Tennessee Valley Authority | 1 | SERC |
| | | | | | Ian Grant | Tennessee Valley Authority | 3 | SERC |
| | | | | | Brandy Spraker | Tennessee Valley Authority | 5 | SERC |
| | | | | | Marjorie Parsons | Tennessee Valley Authority | 6 | SERC |
| Seattle City Light | Ginette Lacasse | 1,3,4,5,6 | WECC | Seattle City Light Ballot Body | Pawel Krupa | Seattle City Light | 1 | WECC |
| | | | | | Hao Li | Seattle City Light | 4 | WECC |
| | | | | | Bud (Charles) Freeman | Seattle City Light | 6 | WECC |
| | | | | | Mike Haynes | Seattle City Light | 5 | WECC |
| | | | | | Michael Watkins | Seattle City Light | 1,4 | WECC |
| | | | | | Faz Kasraie | Seattle City Light | 5 | WECC |
| | | | | | John Clark | Seattle City Light | 6 | WECC |

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|---|---|---|---|---|---|---|---|---|
| | | | | | Tuan Tran | Seattle City Light | 3 | WECC |
| | | | | | Laurrie Hammack | Seattle City Light | 3 | WECC |
| Public Utility District No. 1 of Chelan County | Haley Sousa | 5 | | Chelan PUD | Davis Jelusich | Public Utility District No. 1 of Chelan County | 6 | WECC |
| | | | | | Joyce Gundry | Public Utility District No. 1 of Chelan County | 3 | WECC |
| | | | | | Jeff Kimbell | Public Utility District No. 1 of Chelan County | 1 | WECC |
| | | | | | Haley Sousa | Public Utility District No. 1 of Chelan County | 5 | WECC |
| DTE Energy - Detroit Edison Company | Jeffrey DePriest | 3,4,5 | | DTE Electric | Karie Barczak | DTE Energy - Detroit Edison Company | 3 | RF |
| | | | | | Daniel Herring | DTE Energy - Detroit Edison Company | 4 | RF |
| JEA | Joe McClung | 3,5 | FRCC | JEA Voters | Ted Hobson | JEA | 1 | FRCC |
| | | | | | Garry Baker | JEA | 3 | FRCC |
| | | | | | John Babik | JEA | 5 | FRCC |
| Lincoln Electric System | Kayleigh Wilkerson | 5 | | Lincoln Electric System | Kayleigh Wilkerson | Lincoln Electric System | 5 | MRO |
| | | | | | Eric Ruskamp | Lincoln Electric System | 6 | MRO |
| | | | | | Jason Fortik | Lincoln Electric System | 3 | MRO |
| | | | | | Danny Pudenz | Lincoln Electric System | 1 | MRO |
| National Grid USA | Michael Jones | 1 | | National Grid | Michael Jones | National Grid USA | 1 | NPCC |
| | | | | | Brian Shanahan | National Grid USA | 3 | NPCC |

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|---|---|---|---|---|---|---|---|---|
| Manitoba Hydro | Mike Smith | 1 | | Manitoba Hydro | Yuguang Xiao | Manitoba Hydro | 5 | MRO |
| | | | | | Karim Abdel-Hadi | Manitoba Hydro | 3 | MRO |
| | | | | | Blair Mukanik | Manitoba Hydro | 6 | MRO |
| | | | | | Mike Smith | Manitoba Hydro | 1 | MRO |
| Southern Company - Southern Company Services, Inc. | Pamela Hunter | 1,3,5,6 | SERC | Southern Company | Katherine Prewitt | Southern Company Services, Inc. | 1 | SERC |
| | | | | | Joel Dembowski | Southern Company - Alabama Power Company | 3 | SERC |
| | | | | | William D. Shultz | Southern Company Generation | 5 | SERC |
| | | | | | Jennifer G. Sykes | Southern Company Generation and Energy Marketing | 6 | SERC |
| BC Hydro and Power Authority | Patricia Robertson | 1,3,5 | | BC Hydro | Patricia Robertson | BC Hydro and Power Authority | 1 | WECC |
| | | | | | Venkataramakrishnan Vinnakota | BC Hydro and Power Authority | 2 | WECC |
| | | | | | Pat G. Harrington | BC Hydro and Power Authority | 3 | WECC |
| | | | | | Clement Ma | BC Hydro and Power Authority | 5 | WECC |
| Eversource Energy | Quintin Lee | 1 | | Eversource Group | Timothy Reyher | Eversource Energy | 5 | NPCC |
| | | | | | Mark Kenny | Eversource Energy | 3 | NPCC |
| | | | | | Quintin Lee | Eversource Energy | 1 | NPCC |
| Northeast Power Coordinating Council | Ruida Shu | 1,2,3,4,5,6,7,8,9,10 | NPCC | RSC no Hydro One, NYISO and Eversource | Guy V. Zito | Northeast Power Coordinating Council | 10 | NPCC |

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|---|---|---|---|---|---|---|---|---|
| | | | | | Randy MacDonald | New Brunswick Power | 2 | NPCC |
| | | | | | Wayne Sipperly | New York Power Authority | 4 | NPCC |
| | | | | | Glen Smith | Entergy Services | 4 | NPCC |
| | | | | | Brian Robinson | Utility Services | 5 | NPCC |
| | | | | | Bruce Metruck | New York Power Authority | 6 | NPCC |
| | | | | | Alan Adamson | New York State Reliability Council | 7 | NPCC |
| | | | | | Edward Bedder | Orange & Rockland Utilities | 1 | NPCC |
| | | | | | David Burke | Orange & Rockland Utilities | 3 | NPCC |
| | | | | | Michele Tondalo | UI | 1 | NPCC |
| | | | | | Laura Mcleod | NB Power | 1 | NPCC |
| | | | | | David Ramkalawan | Ontario Power Generation Inc. | 5 | NPCC |
| | | | | | Helen Lainis | IESO | 2 | NPCC |
| | | | | | Michael Schiavone | National Grid | 1 | NPCC |
| | | | | | Michael Jones | National Grid | 3 | NPCC |
| | | | | | Silvia Mitchell | NextEra Energy - Florida Power and Light Co. | 6 | NPCC |
| | | | | | Michael Forte | Con Ed - Consolidated Edison | 1 | NPCC |
| | | | | | Daniel Grinkevich | Con Ed - Consolidated Edison Co. of New York | 1 | NPCC |
| | | | | | Peter Yost | Con Ed - Consolidated | 3 | NPCC |

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| | | | | | | Edison Co. of New York | | |
| | | | | | Brian O'Boyle | Con Ed - Consolidated Edison | 5 | NPCC |
| | | | | | Sean Cavote | PSEG | 4 | NPCC |
| | | | | | Sean Bodkin | Dominion - Dominion Resources, Inc. | 6 | NPCC |
| | | | | | Sylvain Clermont | Hydro Quebec | 1 | NPCC |
| | | | | | Chantal Mazza | Hydro Quebec | 2 | NPCC |
| | | | | | Kathleen Goodman | ISO-NE | 2 | NPCC |
| Midwest Reliability Organization | Russel Mountjoy | 10 | | MRO NSRF | Joseph DePoorter | Madison Gas & Electric | 3,4,5,6 | MRO |
| | | | | | Larry Heckert | Alliant Energy | 4 | MRO |
| | | | | | Amy Casucelli | Xcel Energy | 1,3,5,6 | MRO |
| | | | | | Michael Brytowski | Great River Energy | 1,3,5,6 | MRO |
| | | | | | Jodi Jensen | Western Area Power Administratino | 1,6 | MRO |
| | | | | | Kayleigh Wilkerson | Lincoln Electric System | 1,3,5,6 | MRO |
| | | | | | Mahmood Safi | Omaha Public Power District | 1,3,5,6 | MRO |
| | | | | | Brad Parret | Minnesota Power | 1,5 | MRO |
| | | | | | Terry Harbour | MidAmerican Energy Company | 1,3 | MRO |
| | | | | | Tom Breene | Wisconsin Public Service | 3,5,6 | MRO |
| | | | | | Jeremy Volls | Basin Electric Power Coop | 1 | MRO |
| | | | | | Kevin Lyons | Central Iowa Power Cooperative | 1 | MRO |
| | | | | | Mike Morrow | Midcontinent Independent System Operator | 2 | MRO |

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|---|---|---|---|---|---|---|---|---|
| Scott Miller | Scott Miller | | SERC | MEAG Power | Roger Brand | MEAG Power | 3 | SERC |
| | | | | | David Weekley | MEAG Power | 1 | SERC |
| | | | | | Steven Grego | MEAG Power | 5 | SERC |
| Southwest Power Pool, Inc. (RTO) | Shannon Mickens | 2 | SPP RE | SPP Standards Review Group | Shannon Mickens | Southwest Power Pool Inc. | 2 | SPP RE |
| | | | | | Don Schmit | Nebraska Public Power District | 5 | SPP RE |
| | | | | | Amy Casuscelli | Xcel Energy | 1,3,5,6 | SPP RE |
| | | | | | Mike Kidwell | Empire District Electric Company | 1,3,5 | SPP RE |
| | | | | | Kiet Nguyen | Grand River Damn Authority | 1 | SPP RE |
| | | | | | louis Guidry | Cleco | 1,3,5,6 | SPP RE |
| | | | | | Tara Lightner | Sunflower Electric Power Corporation | 1 | SPP RE |
| | | | | | Kevin Giles | Westar Energy | 1 | SPP RE |
| PPL - Louisville Gas and Electric Co. | Shelby Wade | 1,3,5,6 | RF,SERC | PPL NERC Registered Affiliates | Charlie Freibert | LG&E and KU Energy, LLC | 3 | SERC |
| | | | | | Brenda Truhe | PPL Electric Utilities Corporation | 1 | RF |
| | | | | | Dan Wilson | LG&E and KU Energy, LLC | 5 | SERC |
| | | | | | Linn Oelker | LG&E and KU Energy, LLC | 6 | SERC |
| OGE Energy - Oklahoma Gas and Electric Co. | Sing Tay | 6 | SPP RE | OKGE | Sing Tay | OGE Energy - Oklahoma Gas and Electric Co. | 6 | SPP RE |
| | | | | | Donald Hargrove | OGE Energy - Oklahoma Gas and Electric Co. | 3 | SPP RE |
| | | | | | Terri Pyle | OGE Energy - Oklahoma Gas and Electric Co. | 1 | SPP RE |

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| | | | | | John Rhea | OGE Energy - Oklahoma Gas and Electric Co. | 5 | SPP RE |

| 1. Do you agree with the creation of the proposed P8 event? | |
|---|---|
| **Joe McClung - JEA - 3,5 - FRCC, Group Name** JEA Voters | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

JEA appreciates the effort of the SDT to address the directives from the Commission on Order No. 786 as well as the recommendation in response to Order No. 754 from the SPCS and the SAMS from the assessment of protection system single points of failure (Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request which hereafter is called “Joint Report”).

However, the proposed addition of the P8 event in Table 1 is overreaching and beyond what is required in the Standards Authorization Request (SAR) which states that the primary goal is to implement the recommendations in the Joint Report. Although the Joint Report listed as one alternative the elevation of the P8 type events ‘to a planning event with its own system performance criteria’ (Joint Report, **Chapter 2 – Alternatives**, pg 9), it did NOT recommend this alternative. The Joint Report cited the fact that “**Probability of three phase fault with a protection system failure is low enough that it does not warrant a planning event**”. The creation of the proposed P8 event in this version has clearly overlooked this fact.

The Joint Report does agree that there is “the existence of a reliability risk associated with the single points of failure in protection system that warrants further action” (JEA agrees with this conclusion). This is why it recommended that additional emphasis in planning studies is needed to assess three-phase faults involving protection system single points of failure (Joint Report, **Chapter 3 – Conclusion**, pg 11). Accordingly, the SAR has defined the scope of the SDT’s work to specifically address only the recommendations from the Joint Report. However, the proposed P8 event in Table 1 goes outside the scope mandated by the SAR because R2.7 requires the Planning Assessment to have a Corrective Action Plan if the “analysis indicates an inability of the System to meet the performance requirements in Table 1” which would include the P8 event.

Except for the proposed R4.5 in draft 2 (Sept. 2017), the SDT addressed all of the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the Joint Report. The clarification of relay to components of a Protection System with the modified Footnote 13 to clarify P5 and extreme events – stability 2e-2h was a significant improvement to the proposed TPL-001-5.

**Suggestion**: The creation of the proposed P8 event is NOT warranted and should be removed. This occurrence of this type of event is very rare in power system disturbances. The proposed Footnote 13 in draft 3 (Mar. 2018 version) should be kept. The deleted portions under Requirement R4 sub-requirement 4.5 in draft 3 should not be deleted, i.e., this sub-requirement should be kept intact from the original TPL-001-4 (the currently enforceable version; from Order No. 786). This sub-requirement 4.5 together with clarified P5 (Table 1), extreme events – stability 2e-2h (Table 1, from draft 2) and the clarified Footnote 13 will adequately address the Commission’s concern, recommendations from the Joint Report as well as the SAR regarding the single points of failure in Protection System.

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| Likes 1 | JEA, 5, Babik John |
| Dislikes 0 | |
| **Response** | |
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| **Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 6** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

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|---|---|
| NextEra does not support P8 events being considered as planning events instead of extreme events. A 3PH fault plus protection system failure is a very low probability event.Ne | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| For the HV BES level, both Categories P5 and the new P8 events require the same performance for both a SLG fault and a 3-Phase fault. BPA believes the performance for the existing P5 is more conservative and the P8 Category is not required for the HV BES level. In addition, BPA suggests deleting the new P8 and modifying P5 to include a row for 3Ø (three phase) for the EHV BES level only allowing interruption of firm transmission service and non-consequential load loss. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Bridget Silvia - Sempra - San Diego Gas and Electric - 3** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| Adding P8 changes a an EXTREME contingency to a CREDABLE contingency. A 3 phase fault with delayed clearing was an extreme event under category D on Table 1 of the original TPL standards. This contingency has always been an extreme contingency. The question not being addressed is, “what reliability improvement can be accomplished by adding P8?”. If P8 studies show instability, there is no requirement for a corrective action plan. Keeping in mind that this is a required standard, why create a P8 contingency, which will increase the work load and cause additional distractions, when the results don’t matter? | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC** | |

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| **Answer** | No |
| **Document Name** | |

**Comment**

Seminole is in agreement with the comments submitted by JEA but would like to provide additional comments relating to the proposed P8 Event. In reviewing the Cost Effectiveness document, the Technical Rationale, the SPCS/SAMS Order 754 Report, and the proposed redline to the existing TPL-001 Reliability Standard, Seminole does not believe that the proposed P8 Planning Event is prudent and the technical rationale is flawed in light of what the SPCS/SAMS documented in their review of the Order 754 Data Request analysis. As documented by JEA, the SPCS/SAMS never recommended making a three-phase fault with a single point of failure a Planning Event unless it included its own performance criteria. Additionally, the SDT and the SPCS/SAMS clearly recognize that a three-phase fault is in and of itself an event that has a low probability of occurrence, and adding a low probabilistic single point of failure of a protection system on top and requiring that this be analyzed as a Planning Event is beyond prudent planning and results in diminishing returns from an analysis and cost effectiveness standpoint. The SDT also made a gross assumption in regards to the amount of work required to evaluate these events by stating that the P8 Planning Event does not require steady state evaluation and “ONLY” requires stability analysis as to insinuate that the level of work is somehow lessened by making this statement.

The cost effectiveness document falls short of providing any substantive cost effectiveness in regards to the additional analysis that would be required by the addition of Planning Event P8

Suggestion:

The existing Extreme Event within Table 1, 2f., allows for the Transmission Planner to use operating experience to develop a contingency event that would result in a wide-area disturbance, such a disturbance that one could presume would cause Cascading, voltage instability or uncontrolled islanding. Operating experience would bring one to the conclusion that the proposed P8 Planning Event is in fact a low probabilistic event and should NOT be considered a Planning Event but rather an Extreme event that is already part of the Extreme Event Table within Table 1

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| Likes 0 | |
| Dislikes 0 | |

**Response**

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| **Jeff Landis - Platte River Power Authority - 3** |

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| **Answer** | No |
| **Document Name** | |

**Comment**

PRPA supports JEA comments.

JEA appreciates the effort of the SDT to address the directives from the Commission on Order No. 786 as well as the recommendation in response to Order No. 754 from the SPCS and the SAMS from the assessment of protection system single points of failure (Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request which hereafter is called “Joint Report”).

However, the proposed addition of the P8 event in Table 1 is overreaching and beyond what is required in the Standards Authorization Request (SAR) which states that the primary goal is to implement the recommendations in the Joint Report. Although the Joint Report listed as one alternative the elevation of the P8 type events ‘to a planning event with its own system performance criteria’ (Joint Report, Chapter 2 – Alternatives, pg 9), it did NOT recommend this alternative. The Joint Report cited the fact that “Probability of three phase fault with a pro low enough that it does not warrant a planning event". The creation of the proposed P8 event in this version has clearly overlooked this fact.

The Joint Report does agree that there is "the existence of a reliability risk associated with the single points of failure in protection system that warrants further action" (JEA agrees with this conclusion). This is why it recommended that additional emphasis in planning studies is needed to assess three-phase faults involving protection system single points of failure (Joint Report, Chapter 3 – Conclusion, pg 11). Accordingly, the SAR has defined the scope of the SDT's work to specifically address only the recommendations from the Joint Report. However, the proposed P8 event in Table 1 goes outside the scope mandated by the SAR because R2.7 requires the Planning Assessment to have a Corrective Action Plan if the "analysis indicates an inability of the System to meet the performance requirements in Table 1" which would include the P8 event.

Except for the proposed R4.5 in draft 2 (Sept. 2017), the SDT addressed all of the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the Joint Report. The clarification of relay to components of a Protection System with the modified Footnote 13 to clarify P5 and extreme events – stability 2e-2h was a significant improvement to the proposed TPL-001-5.

Suggestion: The creation of the proposed P8 event is NOT warranted and should be removed. This occurrence of this type of event is very rare in power system disturbances. The proposed Footnote 13 in draft 3 (Mar. 2018 version) should be kept. The deleted portions under Requirement R4 subrequirement 4.5 in draft 3 should not be deleted, i.e., this sub-requirement should be kept intact from the original TPL-001-4 (the currently enforceable version; from Order No. 786). This subrequirement 4.5 together with clarified P5 (Table 1), extreme events – stability 2e-2h (Table 1, from

Unofficial Comment Form Project 2015-10 and Single Points of Failure | February 2018 3
draft 2) and the clarified Footnote 13 will adequately address the Commission's concern, recommendations from the Joint Report as well as the SAR regarding the single points of failure in Protection System.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Thomas Foltz - AEP - 5**

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|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

AEP does not agree with the creation and inclusion of P8 for the following reasons:

1. We see nothing within the project's final SAR which would accommodate the addition of a completely new Performance Planning Event in Table 1. As a result, we believe its proposed inclusion goes beyond the scope of the SAR.

2. The creation of P8 introduces an inconsistent treatment of breaker failure. A 3-phase fault with the failure of a non-redundant component of a Protection System (footnote 13.d, such as the failure of single-control circuitry that would prevent tripping but initiate breaker failure) that results in a breaker failure operation is considered a Planning Event in P8. However, the same 3-Phase fault with a stuck breaker is included under Extreme events in the Stability column and results *in the exact same event*. If a 3-phase fault results in a breaker failure operation, what is the reliability benefit of differentiating the cause between a Protection System component failure or a stuck breaker? While AEP disagrees with many aspects of the recently-proposed revisions, the concerns expressed in this paragraph are the primary drivers behind our decision to vote negative during this comment/ballot period.

3. AEP is concerned that the inclusion of P8, coupled with its indistinct relationship to P5, will lead to inconsistent decision-making when using and applying Table 1. This was well illustrated during the March 22nd webinar by both the questions posed and the responses and insight provided by Chris Colson. A number of possible scenarios were provided by remote attendees seeking insight how the table should be correctly applied in those cases. At

times, Mr. Colson expressed appreciation for the thought process, reasoning, and "logical analysis" used by those who were posing the questions and referencing Table 1. Our own impressive was different however, as we believe referencing the Table in such a "nonlinear" or "cyclical" way would actually lead to inconstant interpretation and application of the table. As a result, we believe it is possible (and perhaps even likely) that the table will not be consistently applied.

In our response to Question #4, AEP has provided possible alternatives to P8's inclusion for the drafting team to consider.

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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| **Shawn Abrams - Santee Cooper - 1** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

Santee Cooper supports JEA's comments on this standard. No, the addition of the P8 event in Table 1 goes beyond what is required by the SAR. The Joint Report cited that the probability of a three-phase fault with protection system failure is low enough that it does not warrant a planning event. The creation of the P8 event is not warranted and should be removed.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Russel Mountjoy - Midwest Reliability Organization - 10, Group Name** MRO NSRF | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

We agree with adding 3-phase fault contingency events with delayed clearing due to Footnote 13 non-redundant components for analysis to the TPL-001 standard. However, we propose that these events be added to the Stability 2.a-2.d contingencies in the Extreme Event section of Table 1, rather than a new P8 contingency category in the Planning Event section of Table 1. The level of risk (probability and impact) of these events on BES reliability, as well as the level of Corrective Action Plans that would be triggered by being categorized as Planning Event is unknown. But the reliability impacts the new contingencies can become known, if they are added to the extreme events section. These new contingencies could be reclassified as planning events in a future TPL-001 revision, if warranted by on the results of the extreme event analyses.

If the proposed P8 event contingencies are not reclassified as extreme events, then we suggest the addition of wording (see Footnote 14 suggestion for Question 4). This wording will make it clear to applicable entities and regulators that Transmission Planners (TPs) and Planning Coordinators (PCs) can first perform the 3-phase fault simulations first for contingencies. Then, only simulate a SLG fault of the corresponding contingency, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. The 3-phase fault contingency (P8) is expected to produce more severe System impacts than the corresponding SLG fault contingency (P5). The proposed Footnote 14 will help applicable entities avoid performing a significant amount of unnecessary and duplicative work with the confidence that regulators will not interpret that the unnecessary and duplicative work must be performed.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham**

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|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

I support comments submitted by the MRO NERC Standards Review Forum

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

NIPSCO agrees with JEA's comments.

*JEA appreciates the effort of the SDT to address the directives from the Commission on Order No. 786 as well as the recommendation in response to Order No. 754 from the SPCS and the SAMS from the assessment of protection system single points of failure (Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request which hereafter is called "Joint Report").*

*However, the proposed addition of the P8 event in Table 1 is overreaching and beyond what is required in the Standards Authorization Request (SAR) which states that the primary goal is to implement the recommendations in the Joint Report. Although the Joint Report listed as one alternative the elevation of the P8 type events 'to a planning event with its own system performance criteria' (Joint Report, **Chapter 2 – Alternatives**, pg 9), it did NOT recommend this alternative. The Joint Report cited the fact that "**Probability of three** -ph* ***that it does not warrant a planning event***". The creation of the proposed P8 event in this version has clearly overlooked this fact.*

*The Joint Report does agree that there is "the existence of a reliability risk associated with the single points of failure in protection system that warrants further action" (JEA agrees with this conclusion). This is why it recommended that additional emphasis in planning studies is needed to assess three-phase faults involving protection system single points of failure (Joint Report, **Chapter 3 – Conclusion**, pg 11). Accordingly, the SAR has defined the scope of the SDT's work to specifically address only the recommendations from the Joint Report. However, the proposed P8 event in Table 1 goes* *outside the scope mandated by the SAR because R2.7 requires the Planning Assessment to have a Corrective Action Plan if the "analysis indicates an inability of the System to meet the performance requirements in Table 1" which would include the P8 event.*

*Except for the proposed R4.5 in draft 2 (Sept. 2017), the SDT addressed all of the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the Joint Report. The clarification of relay to components of a Protection System with the modified Footnote 13 to clarify P5 and extreme events – stability 2e-2h was a significant improvement to the proposed TPL-001-5.*

***Suggestion**: The creation of the proposed P8 event is NOT warranted and should be removed. This occurrence of this type of event is very rare in power system disturbances. The proposed Footnote 13 in draft 3 (Mar. 2018 version) should be kept. The deleted portions under Requirement R4 sub-requirement 4.5 in draft 3 should not be deleted, i.e., this sub-requirement should be kept intact from the original TPL-001-4 (the currently enforceable version; from Order No. 786). This sub-requirement 4.5 together with clarified P5 (Table 1), extreme events – stability 2e-2h (Table 1, from draft 2) and the clarified Footnote 13 will adequately address the* Commission's concern, recommendations from the Joint Report as well as the SAR regarding the single points of failure in Protection System.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Marty Hostler - Northern California Power Agency - 5**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

See JEAs response.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name** OKGE

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

OG&E considers the proposal to categorize the P8 event as a Planning Event as being in conflict with the SPCS (System Protection and Control Subcommittee) and the SAMS (System Analysis and Modeling Subcommittee) recommendations contained in its "Order No. 754: Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request" white paper ("Joint Report"). The SPCS and SAMS advised that three-phase fault Single Point of Failure events should remain categorized as Extreme Events and that "[probability] of a three-phase fault with a protective system failure is low enough that it does not warrant a planning event." *See* Order 754 Assessment at pp. 9 and 11.

Recommendation: Remove the P8 event from the proposed language. The occurrence of this type of event is rare in power system disturbances. The proposed Footnote 13 in draft 3 (Mar. 2018 version) should be kept. The deleted portions under Requirement R4 subrequirement 4.5 in draft 3 should not be deleted, i.e., this sub-requirement should be kept intact from the original TPL-001-4 (the currently enforceable version; from Order No. 786). This subrequirement 4.5 together with clarified P5 (Table 1), extreme events – stability 2e-2h (Table 1, from draft 2) and the clarified Footnote 13 will adequately address the Commission's concern, recommendations from the Joint Report as well as the SAR regarding the single points of failure in Protection System.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6**

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|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

The roposed addition of the P8 in Table 1 is beyond the standard requirements. the possiblity of this event occuring is very remote. Requirement R4.3 (the deleted portion) should be kept in the standard. The proposed changes does not address any current issues or concerns based on the past history. the changes on the remedia; actopm scheme seems to be appropriate.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins**

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|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

Given the similarities between P5 and P8 events, NVE recommends that the proposed P8 events should replace the existing P5 events. It is expected that in most portions of the BES, there will be few, or no, SLG contingencies that would result in more severe impacts than the corresponding 3 phase fault contingencies with a failed non-redudant component of a Protection System. A Footnote 14 can be added to the Fault Type that allows the Transmission Planner or Planning Coordinator to change the fault type from 3 Phase to L-G based on the failure of the non-redundant component of a Protection System being studied (i.e. a SLG fault for a failure of a single phase electromechanical relay) or based on the impact to the system.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Dennis Sismaet - Northern California Power Agency - 6**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| Please see JEA's comments. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| MEC supports NSRF comments. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Ellen Oswald - Midcontinent ISO, Inc. - 2** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

We agree with adding 3-phase fault contingency events with delayed clearing due to Footnote 13 non-redundant components for analysis to the TPL-001 standard. However, we propose that these events be added to the Stability 2.a-2.d contingencies in the Extreme Event section of Table 1, rather than a new P8 contingency category in the Planning Event section of Table 1. The level of risk (probability and impact) of these events on BES reliability, as well as the level of Corrective Action Plans that would be triggered by being categorized as Planning Event is unknown. But the reliability impacts the new contingencies can become known, if they are added to the extreme events section. These new contingencies could be reclassified as planning events in a future TPL-001 revision, if warranted by on the results of the extreme event analyses.

If the proposed P8 event contingencies are not reclassified as extreme events, then we suggest the addition of wording (see Footnote 14 suggestion for Question 4). This wording will make it clear to applicable entities and regulators that Transmission Planners (TPs) and Planning Coordinators (PCs) can first perform the 3-phase fault simulations first for contingencies. Then, only simulate a SLG fault of the corresponding contingency, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. The 3-phase fault contingency (P8) is expected to produce more severe System impacts than the corresponding SLG fault contingency (P5). The proposed Footnote 14 will help applicable entities avoid performing a significant amount of unnecessary and duplicative work with the confidence that regulators will not interpret that the unnecessary and duplicative work must be performed.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Mike Smith - Manitoba Hydro - 1, Group Name** Manitoba Hydro

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|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

P5 events already covers the concern of failure of non-redundant protection systems with a single line to ground fault. The majority of multiple contingency events in TPL-001 only require analysis of a more frequent single line to ground fault. By including the P8 event, development of a corrective action plan may be required for a very low probability event (3-phase fault plus failure of a protection system). Ideally the drafting team should attempt to calculate probabilities and keep the single and multiple contingency categories within roughly a one in thirty year probability of occurring. All other less frequent events should be considered extreme and it should be up to the discretion of the Transmission Planner/Planning Coordinator whether investment is warranted.

If 3-phase faults are assumed to have a 1 in 10 year frequency and protection failure a 1 in 10 year frequency then a 3 –phase fault with protection failure has a 1 in 100 year frequency. Single phase faults have a higher probability of 1 in 1 year to 1 in 3 year depending on the voltage level. Protection failure with a single phase fault is closer to 1 in 30 years.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

By creating the new “P8” single-point-of-failure category of events and by requiring a Corrective Action Plan (CAP) when such P8 events cause cascading or uncontrolled islanding, the Standard Drafting Team has clearly gone beyond the recommendation in the Standard Authorization Request (SAR). The SAR only recommends that the TPL-001-4 standard be revised “so that extreme event assessments must include evaluation of the three-phase faults with the described component failures of a Protection system.” It does not recommend or require that these new P8 events, which are extreme events, be held to a higher standard than thaFlppst of the other extreme events with a new event category unto itself. It also does not recommend or require that such events be mitigated with a CAP, a requirement that is not applied to any of the other extreme events. These P8 events are extreme events and should be held to the same criteria that is applied to the other extreme events.

SMUD supports the SAR recommendation to include single-point-of-failure events in its annual assessment of extreme events. SMUD does not, however, support the hard requirement to mitigate such events when studies indicate they may lead to cascading or uncontrolled islanding and prefers instead to leave the decision to mitigate such events to the Planning Coordinator and Transmission Planner just as such discretion exists for all other extreme events.

However, by including the P8 event in Table 1, it inappropriately and erroneously subjects the category P8, extreme events, to Requirement 2.7 that requires a CAP when performance requirements are not met, effectively exceeding the concepts included in the SAR.

The P8 events is an extreme event and needs to be held to the same requirements as applied to other extreme events.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Douglas Johnson - American Transmission Company, LLC - 1**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

We agree with adding 3-phase fault contingency events with delayed clearing due to Footnote 13 non-redundant components for analysis to the TPL-001 standard. However, we propose that these events be added to the Stability 2.a-2.d contingencies in the Extreme Event section of Table 1, rather than a new P8 contingency category in the Planning Event section of Table 1. The level of risk (probability and impact) of these events on BES reliability, as well as the level of Corrective Action Plans that would be triggered by being categorized as Planning Event is unknown. But the reliability impacts the new contingencies can become known, if they are added to the extreme events section. These new contingencies could be reclassified as planning events in a future TPL-001 revision, if warranted by on the results of the extreme event analyses.

If the proposed P8 event contingencies are not reclassified as extreme events, then we suggest the addition of wording (see Footnote 14 suggestion for Question 4). This wording will make it clear to applicable entities and regulators that Transmission Planners (TPs) and Planning Coordinators (PCs) can first perform the 3-phase fault simulations first for contingencies. Then, only simulate a SLG fault of the corresponding contingency, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. The 3-phase fault contingency (P8) is expected to produce more severe System impacts than the corresponding SLG fault contingency (P5). The proposed Footnote 14 will help applicable entities avoid performing a significant amount of unnecessary and duplicative work with the confidence that regulators will not interpret that the unnecessary and duplicative work must be performed.

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|---|---|
| Likes 0 | |

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| Dislikes 0 | |

| **Response** |
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| **Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF** | |
|---|---|
| **Answer** | No |
| **Document Name** | |

| **Comment** |
|---|

Duke Energy disagrees with the creation of the proposed P8 as a Planning Event. The proposed addition of the P8 event goes beyond of what is required in the Standards Authorization Request (SAR). The joint report by the SPCS and SAMS subcommittees considered the events (similar to the proposed P8) to be ‘elevated to a planning event with its own system performance criteria’ (Chapter 2 – Alternatives of the Joint-report) as one of the alternatives, however, the joint report did NOT recommend this alternative citing the fact that “Probability of three [illegible] failure is low enough that it does not warrant a planning event”.

The probability of this event occurring is low, and the change of “relay” to “components of a Protection System” with the modified Footnote 13 to clarify P5 and extreme events – stability 2e-2h is a significant improvement to the proposed TPL-001-5. It addresses ALL the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the Joint-report.

The implementation of the proposed P8 event is NOT needed and should be removed. We believe that Requirement 4 sub-requirement 4.2 together with clarified P5 (Table 1), modified extreme events – stability 2e-2h (Table 1), and the clarified Footnote 13 will adequately address the Commission’s concerns.

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| Likes 0 | |
| Dislikes 0 | |

| **Response** |
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| **Chris Scanlon - Exelon - 1, Group Name** Exelon Utilities | |
|---|---|
| **Answer** | No |
| **Document Name** | |

| **Comment** |
|---|

Neither the SAR, FERC Orders, or the SPCS/SAMS report appear to require or explicitly recommend the creation of a new planning event type in order to address single-point-of failure. Based on the data reported in NERC’s analysis of the Order 754 Data Request, the conclusion can be drawn that the majority of scenarios which will need to be analyzed under the P8 event will consist of lower voltage facilities which are less likely to create an “adverse system impact” as compared to higher voltage facilities that are more likely to have fully redundant protection systems. Such events are already included under the existing category of “extreme events” – a more efficient way to address the risks of critical SPF scenarios (as well as other critical vulnerabilities that might exist) might be to direct the TP or PC to develop a more defined process to screen extreme events, identify those which pose the greatest risk, and to determine those that may be appropriate to study and possibly mitigate.

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| Likes 0 | |
| Dislikes 0 | |

| Response |
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| **John Bee - Exelon - 3** |

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| --- | --- |
| **Answer** | No |
| **Document Name** | |

**Comment**

See Exelon TO Utilities Comments

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| --- | --- |
| Likes 0 | |
| Dislikes 0 | |

| Response |
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**Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name** FMPA

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| --- | --- |
| **Answer** | No |
| **Document Name** | FMPA_2015-10_Unofficial_Comment_Form_2018423_2_.docx |

**Comment**

FMPA disagrees for the following reasons.

1. The revisions exceed the properly and dutifully developed scope of the SAR, and do so without any substantiated basis (e.g. there is no “new evidence” to suggest the scope of the SAR should have been exceeded). Creating a Planning level event was a specific option considered by the NERC System Protection and Control Subcommittee (SPCS) and System Analysis and Modeling subcommittee (SAMS) in their joint report, referenced in the Technical Rationale for this Project. The purpose of the SAMS/SPCS joint report was to evaluate the available data and make a recommendation as to the level of reliability risk that did, or did not, exist, and recommend paths forward to address those risks. Industry provided the data for the Section 1600 data request dutifully and faithfully entrusting SPCS and SAMS to carefully anyalze that data and make reasonable recommendations to industry, NERC and FERC based on the evidence. This is what SPCS and SAMS did. The joint report concluded a Planning level event was not warranted and made recommendations to ensure that Protection system failures with three phase faults were studied as extreme events.

2. Elevating an event to a Planning event when data does not suggest this is warranted creates complexity and confusion and puts other events at risk of the same fate and changes aspects of the planning standard that were working well and did not need to be changed. The joint report concluded there was a reliability risk. FMPA agrees with this. The joint report recommended modifying the extreme events and footnote 13 in the TPL-001-4 standard. Again, FMPA agrees with this approach – it makes sense given the data that industry provided in the Section 1600 data request. Effectively, a protection system failure with a three phase fault represents the same reliability risk as a breaker failure event with a three phase fault, which is already studied as an extreme event. This grouping was already contemplated in the prior revision of TPL-001-4; it was the over-simplification of the description of protection systems in the footnotes and lack of explicit statements in the extreme events list in Table 1 that created the reliability gap. The end result

of creating a Planning level event for Protection System failures would be to send the message that the other three phase fault extreme events which are statistically equivalent to them should also be studied as planning events.

3. FMPA disagrees with the Technical Rationale on three points and therefore does not agree that introduction of this P8 event is justified or warranted:

A. The Technical Rationale for this Project makes the argument that the reason a Planning Event is warranted is the mere fact that the joint report exists – a report which concluded the exact opposite. This makes no sense, and serves to undermine all the work industry, SPCS, and SAMS did in investigating the reliability risks and determining a path forward to address those risks.

B. The Technical Rationale’s assertion that elevating protection system failures to a Planning Event is not significant since CAPs are only required if there is a risk of Cascading or or widespread electric service disruption doesn’t make sense, since industry has previously, and through much development and debate, established the clear line that Planning events are based on more rigorous performance criteria than this. Hence, an event that is only required to be remedied if it causes Cascading or widespread electric service disruption (but not other performance criteria violations) is not a Planning Event and doing so only creates confusion in the standard where previously there was clarity.

C. FMPA also feels it is poor justification to claim that the prior round of industry comments requested the creation of this Planning event. The prior industry comments were solely a reaction to the confusion that was introduced into the standard when the SDT attempted to exceed the scope of the SAR by creating a quasi-third performance category. The result of this was industry felt forced to pick sides. FMPA does not believe any entity in industry, not one single commenter, would have recommended a Planning event if the original draft that was posted for comment had followed the scope of the SAR and left these events as extreme events where they belong.

FMPA would support doing what was recommended by the SPCS/SAMS joint report and what was written in the SAR for this project, and does not support exceeding the scope of the SAR nor the recommendation of the joint report, which this current proposition does. It is of the utmost importance that we send a message to industry that, when a 1600 data request is prepared and industry is asked to carefully analyze an issue, we will make use of that analysis and value it, and that when we request that changes to standards be based on careful, logical analysis, and that careful, logical analysis is completed, we follow the recommendations of that analysis.

To be very clear: FMPA believes protection system failures should be studied, and FMPA already studies protection system failures in a rigorous fashion.It is quite likely that, should FMPA identify performance issues due to protection system failures in its studies, FMPA and/or its members would upgrade its/their protection systems to address the observed issues. That is, good engineering and planning practices will be followed. However, FMPA believes that any system upgrades or CAPs that are mandated by the standard language should be based on reliability risks; and not just because they are “inexpensive or “easy”.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

We agree with adding 3-phase fault contingency events with delayed clearing due to Footnote 13 non-redundant components for analysis to the TPL-001 standard. However, we propose that these events be added to the Stability 2.a-2.d contingencies in the Extreme Event section of Table 1, rather than a new P8 contingency category in the Planning Event section of Table 1. The level of risk (probability and impact) of these events on BES reliability, as well as the level of Corrective Action Plans that would be triggered by being categorized as Planning Event is unknown. But the reliability impacts the new contingencies can become known, if they are added to the extreme events section. These new contingencies could be reclassified as planning events in a future TPL-001 revision, if warranted by on the results of the extreme event analyses.

If the proposed P8 event contingencies are not reclassified as extreme events, then we suggest the addition of wording (see Footnote 14 suggestion for Question 4). This wording will make it clear to applicable entities and regulators that Transmission Planners (TPs) and Planning Coordinators (PCs) can first perform the 3-phase fault simulations first for contingencies. Then, only simulate a SLG fault of the corresponding contingency, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. The 3-phase fault contingency (P8) is expected to produce more severe System impacts than the corresponding SLG fault contingency (P5). The proposed Footnote 14 will help applicable entities avoid performing a significant amount of unnecessary and duplicative work with the confidence that regulators will not interpret that the unnecessary and duplicative work must be performed.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman**

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|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

See comments from MRO NSRF.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6; - Michael Brytowski**

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|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

GRE agrees with the MRO NSRF and ACES comments.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Robert Ganley - Long Island Power Authority - 1**

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|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

Due to possible confusion with interpretation of the new P8 event, we do not fully agree with the implementation of the new event in the Standard.

The distinction and required performance criteria for the P5 and P8 events should be clarified and specifically documented within the Standard. As presented, Table 1 (Steady State & Stability Performance Planning Events) is difficult to interpret. One method to clarify the table might be to separate out the P8 event within Table 1 (Steady State & Stability Performance Planning Events) and specifically document the steady state and stability performance requirements for P8.

For example, it is not clear from the Standard if a Corrective Action Plan is only required if the P8 event results in Cascading.

One additional observation for Table 1 (Steady State & Stability Performance Planning Events). Per Table 1, steady state and stability analysis is applicable for the P5 event and the P8 event. The implementation of the P5 event and the P8 event in steady state analysis will likely be identical for both of these events (since fault type usually is not considered). However,

- for P5, Non-Consequential Load Loss is not allowed for EHV facilities.
- For P8, Non-Consequential Load Loss is allowed for EHV facilities.

This is a possible contradiction that should be reviewed and clarified.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller, Group Name** MEAG Power

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

The proposed addition of the P8 event in Table 1 is overreaching and beyond what is required in the Standards Authorization Request (SAR) which states that the primary goal is to implement the recommendations in the Joint Report. Although the Joint Report listed as one alternative the elevation of the P8 type events 'to a planning event with its own system performance criteria' (Joint Report, ***Chapter 2 – Alternatives***, pg 9), it did NOT recommend this alternative. The Joint Report cited the fact that "***Probability of three-phase faults with a protection system failure is low enough that it does not warrant a planning event***". The creation of the proposed P8 event in this version has clearly overlooked this fact.

The Joint Report does agree that there is *"the existence of a reliability risk associated with the single points of failure in protection system that warrants further action"* (We agree with this conclusion). This is why it recommended that additional emphasis in planning studies is needed to assess three-phase faults involving protection system single points of failure (Joint Report, ***Chapter 3 – Conclusion***, pg 11). Accordingly, the SAR has defined the scope of the SDT's work to specifically address only the recommendations from the Joint Report. However, the proposed P8 event in Table 1 goes outside the scope mandated by the SAR because R2.7 requires the Planning Assessment to have a Corrective Action Plan if the "analysis indicates an inability of the System to meet the performance requirements in Table 1" which would include the P8 event.

Except for the proposed R4.5 in draft 2 (Sept. 2017), the SDT addressed all of the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the Joint Report. The clarification of relay to components of a Protection System with the modified Footnote 13 to clarify P5 and extreme events – stability 2e-2h was a significant improvement to the proposed TPL-001-5.

**Suggestion: The creation of the proposed P8 event is NOT warranted and should be removed. This occurrence of this type of event is very rare in power system disturbances. The proposed Footnote 13 in draft 3 (Mar. 2018 version) should be kept. The deleted portions under Requirement R4 sub-requirement 4.5 in draft 3 should not be deleted, i.e., this sub-requirement should be kept intact from the original TPL-001-4 (the currently enforceable version; from Order No. 786). This sub-requirement 4.5 together with clarified P5 (Table 1), extreme events – stability 2e-2h (Table 1, from draft 2) and the clarified Footnote 13 will adequately address the Commission's concern, recommendations from the Joint Report as well as the SAR regarding the single points of failure in Protection System.**

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE**

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|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

CenterPoint Energy Houston Electric, LLC ("CenterPoint Energy") does not agree with the creation of the proposed P8 event. A three-phase fault plus delayed fault clearing due to the failure of a non-redundant component of a Protection System in one event is a very rare occurrence in power system disturbances, beyond the scope of a planning event, and therefore should be considered an Extreme Event. As an alternative to the creation of a proposed P8 event, CenterPoint Energy recommends modifying the Extreme Event requirement, as proposed in the approved SAR, to expressly require evaluation of a three-phase fault and Protection System failure.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name** Tennessee Valley Authority

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|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

| | |
|---|---|
| TVA supports JEA's comments. We believe a three-phase fault including protection system failure would have an extremely low probability of occurring. Requiring implementation of actions to prevent these extremely rare events would cause a large and unnecessary financial burden with little benefit to our system reliability. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| See comments below. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Brian Van Gheem - ACES Power Marketing - 6, Group Name** ACES Standards Collaborators | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| We believe the proposed three-phase analysis is duplicative to Category P5 events that study single-phase-to-ground fault types. While three-phase faults can be more severe, the probability of such events are less likely to occur. This could set a precedence requiring PCs and TPs to include other less likely events in their future studies, or held accountable otherwise. We recommend removing this proposed event from the standard and provide registered entities an opportunity to individually address, on their own and not required through this standard, the concerns to BES reliability raised during the FERC Technical Conference, recommendations from various NERC Technical Subcommittees, and the efforts of this SDT. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name** SPP Standards Review Group | |
| **Answer** | No |
| **Document Name** | |

| Comment | |
|---|---|

The SPP Standards Review Group considers the proposal to cateogorize the P8 event as a Planning Event as going beyond the scope of the Federal Energy Regulatory Commission’s (FERC) Order No. 754. The FERC order requires that NERC review how single points of failure on protection systems are studied and identify additional actions necessary to address the matter; however, Order 754 does not require a Corrective Action Plan (CAP) to be developed or implemented. *See* Order No. 754 at PP 19-20. By re-categorizing P8 events as a Planning Event, rather than an Extreme Event, the proposed standard would require the TP to prepare a Corrective Action Plan in accordance with Section 2.7 *et seq.* of TPL-001-4. Summarily, the proposed revision presents a requirement not specifically defined by FERC.

Moreover, the proposal to categorize P8 contigencies as Planning Events conflicts with the SPCS (System Protection and Control Subcommittee) and the SAMS (System Analysis and Modeling Subcommittee) recommendations contained in its Order No. 754 assessment (Joint Report). The SPCS and SAMS advised that P8 events should remain categorized as an Extreme Event and that “[probability] of a three-phase fault with a protective system failure is low enough that it does not warrant a planning event.” *See* Joint Report at 9 and 11.

Recommendations:

1. Remove the P8 event from the proposed language. The occurrence of this type of event is rare in power system disturbances. The proposed Footnote 13 in draft 3 (Mar. 2018 version) should be kept. The deleted portions under Requirement R4 subrequirement 4.5 in draft 3 should not be deleted, i.e., this sub-requirement should be kept intact from the original TPL-001-4 (the currently enforceable version; from Order No. 786). This subrequirement 4.5 together with clarified P5 (Table 1), extreme events – stability 2e-2h (Table 1, from draft 2) and the clarified Footnote 13 will adequately address the Commission’s concerns, recommendations from the Joint Report, and satisfy the objective of the SAR, regarding the single points of failure in Protection Systems.

2. Should the drafting team decide to categorize a P8 contingency as a Planning Event, the drafting team should consider expanding the applicability of the standard to include those functional entities from which the Transmission Planner (TP) must receive system protection data: Generator Owner (GO), Transmission Owner (TO), and Distribution Provider (DP). Because a non-vertically integrated Planning Cooridnator (PC) or TP (e.g., an RTO/ISO) must receive and coordinate system protection data from the GO, TO, and DP in order to satisfy the planning requirements, the standard should be revised to include data submission requirements for the GO ,TO, and DP. The proposed standard’s reliance on MOD-032 as a means to receive system protection data is insufficient because MOD-032 does not specifically require such data be provided to the TP.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

**Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name** Seattle City Light Ballot Body

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

We support JEA comments

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

| Response | |
|---|---|
| | |
| **Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| The focus of the contingencies must be on the likelihood of them happening. P8 contingencies consist of a three-phase fault plus non-redundant component of a protection system failure to operate. Oncor's transmission system experiences very low instances of three-phase faults as compared to single-phase faults. In addition, a three-phase fault with non-redundant component of a protection system failure to operate is even more rare. The likelihood or probability of a P8 contingency occurring is so low that Oncor believes it would not be practical both from an engineering and economical standpoint to elevate this event to a P level contingency. It better fits in the extreme event category. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Seattle City Light - 5 - WECC** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| Jamie Monette - Allete - Minnesota Power, Inc. - 1 | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF | |
|---|---|
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| None. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| David Jendras - Ameren - Ameren Services - 3 | |
|---|---|
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| If the fix for a cascading three-phase fault with delayed clearing event is the installation of a redundant system protection component, we thoroughly support such a change. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| Leonard Kula - Independent Electricity System Operator - 2 | |
|---|---|
| **Answer** | Yes |

| | |
|---|---|
| **Document Name** | |
| **Comment** | |

We agree with the creation of the proposed P8 event.  However, in our view, following a P8 event the tripping of a circuit due to a generator pulling out of synchronism should be permissible as long as it doesn't result in cascading or uncontrolled separation.  The proposed standard requires that for the P8 planning event, "The System Shall remain stable" and "Cascading and uncontrolled islanding shall not occur".  However, since, there isn't a common understanding of what the system remaining stable means, we suggest including the following sub-requirement in the standard for additional clarity:

**4.1.4.  For planning events P8:  When a generator pulls out of synchronism in the simulations, the resulting apparent impendace swings shall not result in Cascading.**

Alternatively, a similar clarification as our proposed sub-requirement 4.1.4 can be added to Condition (a) on top of Table 1 as follows:

**a) For P0 through P7 events, the System shall remain stable, and Cascading and uncontrolled islanding shall not occur. For P8 event, Cascading shall not occur.**

| | |
|---|---|
| Likes 1 | Pathirane Oshani On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; |
| Dislikes 0 | |
| **Response** | |

**Neil Swearingen - Salt River Project - 1,3,5,6 - WECC**

| | |
|---|---|
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |

SRP supports the addition of the P8 event. If the occurrence of a P8 event violates the performance requirements of Table 1, even after Interruption of Firm Transmission Service and Non-Consequential Load Loss, then corrective actions are warranted.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

**Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin**

| | |
|---|---|
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |

ITC agrees with the SDT that the creation of a P8 event is appropriate to build CAP to prevent the system from cascading when a SLG fault propagates into a 3-phase fault.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Rachel Coyne - Texas Reliability Entity, Inc. - 10** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| Texas RE agrees with the creation of the proposed P8 event. Texas RE recommends including Item J in Table 1 in the Steady State & Stability (P0 through P8 events) list as stability issues can be associated with voltage. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name** Southern Company | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| Yes. We agree with adding the proposed P8 event with the understanding that Transmission Planners (TPs) and Planning Coordinators (PCs) can perform the 3-phase fault simulations first for contingencies that are expected to produce more severe System impacts on its portion of the BES, then if needed, the corresponding SLG fault contingency. More specifically, the need to simulate a subsequent SLG fault of the corresponding contingency would be only if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss or Cascading. It is also expected that there will be “extremely few,” or more likely “no”, SLG fault contingencies that would result in more severe impacts than the corresponding 3-phase fault contingencies. Please see comment for Footnote 14 in the responses to Question 4.<br><br>It is difficult to ascertain the simulation performance requirement for P8 events. To help clarify these performance requirements for the proposed P8 events, suggest inserting R4.1.4 that reads: For planning event P8, the System shall remain stable, and Cascading and uncontrolled islanding shall not occur. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2** | |
| **Answer** | Yes |

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|---|---|
| **Document Name** | |
| **Comment** | |
| The proposed revisions to the Steady State and Stability performance requirements in Table 1 imply that a P8 event must not result in Cascading, instability, and islanding. This exceeds the SDT's original intent to require development and implementation of a CAP to avoid Cascading only.<br><br>To remove the performance requirements for instability and islanding for a P8 event, ERCOT suggests the following wording changes to Condition (a):<br><br>(a) For P0 through P7 events, the System shall remain stable, and Cascading and uncontrolled islanding shall not occur. For P8 event, Cascading shall not occur. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Jeffrey DePriest - DTE Energy - Detroit Edison Company - 3,4,5, Group Name** DTE Electric | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1** | |
| **Answer** | Yes |
| **Document Name** | |

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|---|---|
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Hasan Matin - Orlando Utilities Commission - 2 - FRCC** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **John Seelke - LS Power Transmission, LLC - 1** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Kelsi Rigby - APS - Arizona Public Service Co. - 5** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

| | |
|---|---|
| **Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Fred Frederick - Southern Indiana Gas and Electric Co. - 3** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Quintin Lee - Eversource Energy - 1, Group Name** Eversource Group | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |

| | |
|---|---|
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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name** PPL NERC Registered Affiliates | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Michael Jones - National Grid USA - 1, Group Name** National Grid | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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| | |
|---|---|
| **Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name** RSC no Hydro One, NYISO and Eversource | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Teresa Cantwell - Lower Colorado River Authority - 5** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name** Chelan PUD

| | |
|---|---|
| **Answer** | |
| **Document Name** | |

**Comment**

CHPD appreciates the effort of the SDT to address the directives from FERC Order No. 786, and the recommendations in response to Order No. 754 from the SPCS and the SAMS regarding the assessment of protection system single points of failure (Order No. 754 Assessment of Protection System Single Points of Failure Based on the Section 1600 Data Request (“Joint Report”)).

Indeed, the primary goal of the Standards Authorization Request (SAR) is to implement the recommendations in the Joint Report.  However, the Joint Report states that “***probability of three*** ***-phase fa*** ***event.***”  As such, we believe that the proposed addition of the P8 planning event is overreaching and beyond the scope of the SAR.

The Joint Report does acknowledge *“the existence of a reliability risk associated with the single points of failure in protection system that warrants further action”* and therefore recommended  additional emphasis in planning studies to assess three-phase faults involving protection system single points of failure (Joint Report, ***Chapter 3 – Conclusion***, pg. 11).  Accordingly, the SAR defined the scope of the SDT’s work to specifically address only the recommendations from the Joint Report.  However, the proposed P8 event falls outside the scope of the SAR because R2.7 requires the Planning Assessment to have a Corrective Action Plan (CAP) if the “analysis indicates an inability of the System to meet the performance requirements in Table 1” which includes the P8 event.

With the exception of the proposed R4.5 in draft 2 (Sept. 2017), the SDT addressed all of the recommendations from SPCS and SAMS regarding single points of failure in protection systems in the Joint Report. The clarification of relay to components of a Protection System with the modified Footnote 13 to clarify P5 and extreme events – stability 2e-2h was a significant improvement to the proposed TPL-001-5.

The proposed Footnote 13 in draft 3 (Mar. 2018 version) should be kept. The deleted portions under Requirement R4 sub-requirement 4.5 in draft 3 should not be deleted, i.e., this sub-requirement should be kept intact from the original TPL-001-4 (the currently enforceable version; from Order No. 786). This sub-requirement 4.5 together with clarified P5 (Table 1), extreme events – stability 2e-2h (Table 1, from draft 2) and the clarified Footnote 13 will adequately address FERC’s concern, recommendations from the Joint Report as well as the SAR regarding the single points of failure in Protection System.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Richard Vine - California ISO - 2**

| | |
|---|---|
| **Answer** | |
| **Document Name** | |

| Comment | |
|---|---|
| The creation of the proposed P8 event raises the following issues:<br><br>The proposed revisions to the Steady State and Stability performance requirements in Table 1 imply that a P8 event must not result in Cascading, instability and islanding. This exceeds the SDT’s original intent to making a 3-phase fault with delayed clearing a planning event thus requiring the development and implementation of a CAP to avoid Cascading only.<br><br>To remove the performance requirements for instability and islanding for a P8 event, we suggest the following wording changes to Condition (a):<br><br>1. For P0 through P7 events, the System shall remain stable, and Cascading and uncontrolled islanding shall not occur. For P8 event, Cascading shall not occur. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

**2. Do you agree with the changes to TPL-001-4 Requirement 1, Part 1.1.2, in order to meet the FERC directive in Order No. 786?**

| **Teresa Cantwell - Lower Colorado River Authority - 5** | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| This change appears to require the creation of a model for every outage, without regard for the length of the outage. The requirement is already part of the performance standard through the application of P5 contingencies. The revision as proposed would require a proliferation of cases be developed and maintained and lead to confusion about which case to use. The development of cases for known outages seems appropriate for the operational time horizon but impracticle for the long-term planning time horizon. Reliability of the system during outages in the long-term planning horizon can be studied appropriately through the development of contingencies accompanied with appropriate generation adjustments to be applied to individual known outages within the seasonal period defined by a planning case as opposed to developing a seperate case for each combination of known outages. Further, the changes proposed under 2.1.3 create confusion around which P1 events need must be studied. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| **Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw** | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| We need clarification. Oncor does not consider known outages to be a modeling issue. Including known outages with other contingencies appears to be more like a P6, two overlapping singles, than a modeling issue. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| **Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name** Seattle City Light Ballot Body | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| City Light would like further clarity of what is expected. | |

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name** SPP Standards Review Group

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|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

The SPP Standards Review Group recommends the drafting team add clarifying language to subparts 2.1.3 and 2.4.3 that specifies how the PC and TP should assess and perform the required studies.

Recommendation:

The following revised language for subparts 2.1.3 and 2.4.3 will provide clarity and eliminate ambiguity how analysis is performed with respect to the subparts previously mentioned (see as follow):

**Subpart 2.1.3 (Proposed language)**

"P1 events in Table 1 expected to produce more severe System impacts on its portion of the Bulk Elextric System (BES), with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions, ***as selected in Part 2.1.1 and 2.1.2***, when known outages are scheduled."

**Subpart 2.4.3 (Proposed language)**

"P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions, ***as selected in Part 2.4.1 and 2.4.2***, when known outages are scheduled."

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Brian Van Gheem - ACES Power Marketing - 6, Group Name** ACES Standards Collaborators

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

We believe the proposed change should be simplified as a procedure or technical rationale that identifies what is a known outage should not be embedded within this requirement. The requirement focuses on maintaining system models, not developing procedures or technical rationales. These models must be based on data consistent with NERC Reliability Standard MOD-032-1, Corrective Action Plans, and other data sources. We recommend the SDT follow the acceptable approach suggested within the FERC directive that identifies significant planned outages can be based on registered entity-selected facility ratings or other parameters for inclusion within system models.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

See comments below.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name** Tennessee Valley Authority

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

TVA supports AZPS's comments. The language is vague and could result in misinterpretation of the requirement. The wording "selected known outages" and "known outages" can cause confusion.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

CenterPoint Energy believes the language in Requirement R1.1.2 could lead to confusion as to which outages are required to be studied. FERC Order 786, paragraph 43 identifies "decreasing the outages to fewer months to include additional significant planned outages" as an acceptable approach. CenterPoint Energy recommends the SDT reconsider this approach and identify a 3-month threshold to capture the outages over which FERC was concerned.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller, Group Name** MEAG Power

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

We agree with removing the Reliability Coordinator from this standard as the responsibility of the RC is "operation" of the system. Also, we believe that using an established procedure or technical rationale to potentially idenifty outages is a step in the right direction.

The concept of known or planned outages in TPL-001-5 needs to have a footnote or further explanation to clarify that this applies to "outages needed to execute the CAP" and be very specific. Also, long term planned generation outages may need to be included. However, maintenance outages should not be addressed in this TPL standard. Maintenance outages are typically not known much more than 6 months out and are assessed by Operations Planning, under TOP and/or IRO standards, closer to the desired time of the maintenance outage such that expected system conditions reflected in the study power flow is better known. Furthermore, since the "Near Term Planning Horizon" covers year 1 through 5, and maintenance outages are not scheduled this far out, then maintenance outages should be not be included in this standard. As such, the exclusion of maintentnace outages for this assessment should be stated in the standard.

Therefore, we recommend that 1.1.2. be modified as follows:

1.1.2 Known Expected outages of generation or Transmission Facility(ies) scheduled in the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Outage(s) shall be selected according to an established process or technical rationale that, at a minimum:

1.1.2.1 Considers any extended outages(s) that are expected during the implementation of identified Corrective Action Plans

1.1.2.2 Considers long term planned generation outages (outside of normal planned and scheduled maintence outage)

1.1.2.4 Does not exclude known transmission outage(s) soley based on the outage duration

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name** Southern Company

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

| Comment |
|---|
| We applaud removing the Reliability Coordinator from this standard as the responsibility of the RC is "operation" of the system. Also, we believe that using an established procedure or technical rationale to potentially idenifty outages is a step in the right direction.<br><br>The concept of known or planned outages in TPL-001-5 needs to have a footnote or further explanation to clarify that this applies to "outages needed to execute the CAP" and be very specific. Also, long term planned generation outages may need to be included. However, maintenance outages should not be addressed in this TPL standard. Maintenance outages are typically not known much more than 6 months out and are assessed by Operations Planning, under TOP and/or IRO standards, closer to the desired time of the maintenance outage such that expected system conditions reflected in the study power flow is better known. Furthermore, since the "Near Term Planning Horizon" covers year 1 through 5, and maintenance outages are not scheduled this far out, then maintenance outages should be not be included in this standard. As such, the exclusion of maintentnace outages for this assessment should be stated in the standard.<br><br>Therefore, we recommend that 1.1.2. be modified as follows:<br><br>1.1.2 **Expected** outages of generation or Transmission Facility(ies) scheduled in the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Outage(s) shall be selected according to an established process or technical rationale that, at a minimum:<br><br>1.1.2.1 Considers any extended outages(s) that are expected during the implementation of identified Corrective Action Plans<br><br>1.1.2.2 Considers long term planned generation outages (outside of normal planned and scheduled maintence outage)<br><br>1.1.2.4 Does not exclude known **transmission** outage(s) soley based on the outage duration |

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| Likes 0 | |
| Dislikes 0 | |

| Response |
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| Rachel Coyne - Texas Reliability Entity, Inc. - 10 | |
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| **Answer** | No |
| **Document Name** | |

| Comment |
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| Texas RE appreciates the Standard Drafting Team's (SDT) continuing efforts to develop a workable definition to implement the Federal Energy Regulatory Commission (FERC) directive in FERC Order No. 786 to include planned maintenance outages of significant facilities in future TPL-001 planning assessments and eliminate the previous six-month bright line inclusion criterion. Texas RE particularly appreciates the SDT's reconsideration of developing a significant outage test based solely upon outages "selected in consultation with the Reliability Coordinator." However, Texas RE remains concerned that the current draft TPL-001-5 R1.1.2 language, if adopted, would be unworkable. Rather than the SDT's proposed approach, Texas RE instead recommends that the SDT require Transmission Planners (TP) and Planning Coordinators (PC) to identify and model known outages selected in accordance with an established procedure that (1) requires selection based on the MW or facility rating criteria identified by FERC in FERC Order No. 786; (2) provides a technical justification for the specific MW and facility rating threshold selected; and (3) does not exclude known outage(s) solely based upon the outage duration. |

Texas RE's principal concern with the proposed TPL-001 language, as currently drafted, is that is appears circular. In particular, the proposed TPL-001-5 R1.1.2 first provides that planning models shall represent "[k]nown outages of generation or Transmission Facility(ies) . . . selected for analyses pursuant to Requirement 2, Parts 2.1.3 and 2.4.3 only." That is, the proposed TPL-001-5 R 1.1.2 appears to limit the scope of modeling requirements to a subset of analyses previously identified in TPL-001-5 R 2.1.3 and 2.4.3. TPL-001-5 R 2.1.3 in turn provides that qualifying studies shall include "P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2." That is to say, the proposed TPL-001-5 R 1.1.2 appears to reference significant outages identified in the qualifying studies in TPL-001-5 R 2.1.3 while the required qualifying studies in TPL-001-5 R 2.1.3 will be based on those known outages identified in the established procedure set forth in TPL-001-5 R 1.1.2. As a result, the proposed language appears circular. That is, TP or PCs will not know which outages to select for their qualifying studies prior to identifying them using their established procedure. However, that procedure itself depends upon a prior identification of known outages in the qualifying study model run.

A similar issue exists in the proposed TPL-001-5 R 2.4.3. This section again requires studies of "P1 events . . . with known outages modeled as in Requirement R1, Part 1.1.2." However, will likely only be able to identify "known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events when concurrent with selected known outage(s)" by performing the analysis in TPL-001-5 R 2.4.3.

In lieu of adopting what appears to be a confusing and circular approach, Texas RE instead recommends that the SDT consider FERC's explicit invitation to define significant known outages based on parameters other than duration. In particular, FERC noted that NERC and the SDT could develop "parameters on what constitutes a significant planned outage based, for example, on MW or facility ratings." (FERC Order No. 786, P. 43). The SDT could implement such a directive by requiring TPs and PCs to select known outages according to an established procedure or technical rationale that, at a minimum, establishes criteria based on MW or facility ratings for significant known outages. Consistent with this approach, the SDT recommends considering revising the proposed TPL-001-5 R 1.1 along the following lines:

1.1 System models shall represent:

1.1.1. Existing Facilities;

1.1.2. Known outages(s) of generation or Transmission Facility(ies) scheduled in the Near-Term Transmission Planning Horizon selected according to an established procedure or technical rationale that, at a minimum:

1.1.2.1 Establishes a criteria, supported by a technical justification, for identifying significant known outages based on MW or facility ratings; and

1.1.2.2. Does not exclude known outage(s) solely based upon the outage duration.

Additionally, it is unclear whose "established procedure" per Part 1.1.4 is to be used, so additional clarification would be helpful.

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| Likes 0 | |
| Dislikes 0 | |

| **Response** |
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| **Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| KCP&L incorporates its response to Question 4. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Michael Jones - National Grid USA - 1, Group Name** National Grid | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| National Grid would like to express our appreciation and supports the direction in which the TPL-001-5 SDT is proposing to adjust the NERC Reliability Standard TPL-001 and provides the following comment for consideration: Generation or Transmission Facilities outages can be scheduled on a time scale shorter than the Near-Term Transmission Planning Horizon. If a Facility outage previously not studied is selected per guidance provided in R1.1.2 and the selected Facility outage occurs within the Near-Term Transmission Planning Horizon, would that prohibit use of past studies to support the annual Planning Assessment (as otherwise allowed per R2.6)? | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6; - Michael Brytowski** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| GRE agrees with the MRO NSRF and ACES comments. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

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| **Neil Swearingen - Salt River Project - 1,3,5,6 - WECC** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| In the last sentence of R1.1.2., SRP recommends changing the word “each” to “all” for the sake of clarity. Also, it is not necessary to specifically list sub-part 1.1.2.2., as there are already other criteria listed which are not solely based on outage duration. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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| **Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| See comments from MRO NSRF. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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| **Leonard Kula - Independent Electricity System Operator - 2** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| We have two concerns with the proposed changes:<br>• As currently proposed, the TPL standard only requires P1 events to be simulated when assessing planned outages in the Near-Term Transmission Planning Horizon. However, this is inconsistent with NERC FAC standard FAC-014-2 R6, which require the Reliablity Co-ordinator to consider multiple contingencies when assessing these outages. Therefore, at a minimum, when the Planning Co-ordinator is assessing planned outages occurring in the Near Term Transmission Planning Horizon, they should simulate the contingences that the Reliablity Co-ordinator would simulate when assessing and approving these outages. Hence we propose to replace the requirement to simulate P1 events in R2.1.3 and R2.4.3 with a requirement to simulate the contingencies as specified per R6 of the current FAC-014-2 standard. | |

- The current proposed requirement for selecting outages does not completely address FERC's order. FERC's order mentions that planned outages should not result in 'the loss of non-consequential load or detrimental impacts to system reliability', whereas the current proposed approach only addresses the loss of non-consequential load.

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| Likes 1 | Pathirane Oshani On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; |
| Dislikes 0 | |

**Response**

**Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6**

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| **Answer** | No |
| **Document Name** | |

**Comment**

We propose the following changes to Part 1.1.2, "Known outage(s) of generation or Transmission Facility(ies) planned to occur in the Near-Term Transmission Planning Horizon for applicable system conditions and year(s) selected by the Transmission Planner or and Planning Coordinator for analyses . . .":

- We suggest replacing the term, "scheduled", with the words, "planned to occur", because the term "scheduled" can be misinterpreted to apply only to outages that are approved and scheduled by Reliability Coordinators. On the other hand, the word "planned to occur" can refer to outages that TPs and PCs know need to be assessed in the planning horizon to implement identified Corrective Action Plans and Facility rebuilds, or know may be difficult or impossible to schedule in the operating horizon without the risk of exceeding System Operating Limits or risk of Non-Consequential Load Loss.

If the term "scheduled" is not replaced and is interpreted to apply only to outages that are approved and scheduled by Reliability Coordinators, then the NERC proposed Part 1.1.2.1 should be removed because Reliability Coordinators only approve scheduled outages in the planning horizon after they assessed for acceptable reliability impact for the applicable system conditions of the outage. So, there is no need to require Planning Coordinators and Transmission Planners to duplicate the assessment of the Reliability Coordinator's scheduled outages.

- We suggest adding, "for applicable system conditions and year (s)", to make clear that the selected outages are related to specific timeframes and are for real applicable system conditions.

- We suggest replacing "Transmission Planner and Planning Coordinator" with "Transmission Planner or Planning Coordinator" because each entity may have valid documented procedures or technical rationale for selecting appropriate outages that differ due to their specific perspectives and roles.

We propose replacing Part 1.1.2.1 with previous proposed wording of, "Are selected in accordance with documented outage selection procedures or technical rationale". If this wording in not added to Part 1.1.2.1, then Part 1.1.2.1 is not a selection limiting criteria. All known outages would have to be evaluated to determine whether any of them are expected to result in Non-Consequential Load Loss for P1 events in Table 1. And since all known outages were studies, then Part 2.1.3 and Part 2.4.3 would have already been performed without any known outage selection limitations.

Furthermore, the proposed Part 1.1.2 text does not address FERC's directive for "NERC to modify Reliability Standard TPL-001-4 to address the concern that the standard could exclude planned maintenance outages of significant facilities from future planning assessments…" [FERC Order 786, Final Rule, Item 3, page 5; Planned Maintenance Outages, pp. 29-37].

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| Likes 0 | |
| Dislikes 0 | |

| Response | |
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| **Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name** FMPA | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

Comments: Addressing Order 786 without adding a tremendous amount of unnecessary study work is admittedly a difficult problem to solve. FMPA does not support the current draft language because it effectively requires that all outages, regardless of the duration, size or location of the facility (really regardless of any qualifier) must be studied. The reason for this is that non-consequential load shedding is rarely possible to identify without running the power system simulations. Thus in order for an entity to only study outages that cause non-consequential load shedding, that entity usually has to have already studied those outages. The suggested “filter” that the SDT is proposing requires that the Planner already know the result of the simulations. The proposed language introduces a standard requirement that, in practice, will result in entities being forced to “prove the negative” – that is, the focus will become defending how the Planner knew that certain outages would not cause non-consequential load loss.

FMPA asserts that some reasonable qualifiers must exist, and must be used in an attempt to avoid requiring entities to prove the negative.  Furthermore, conducting Planning studies on very short duration outages is a waste of time since short duration outages are much more easily (and therefore almost always are) rescheduled in the operations horizon to avoid transmission system reliability risks that are possible. Focusing on longer outage durations increases the likelihood that system performance conditions observed in the studies might actually occur in real time and focuses the study work of the planners more on projects that increase the flexibility of the system (e.g. giving the Operators more tools in their toolbox), rather than on trying to guess at operations horizon conditions or emulate Operations horizon planning work.

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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| **Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

Duke Energy disagrees that the proposed changes meet the directives. The changes go beyond the scope of changes directed in Order No. 786 and will make Planners responsible for evaluating all known scenarios, even outages of limited duration (e.g. 10 minutes?). Also, the standard lacks clarity on whether outages of a Protection System should be considered as well. The lack of specificity regarding outages of limited duration, requires a Planner to study almost every possible scenario Operators may face in the Near Term Planning Horizon.

Further, the proposed changes appear to push the standard to a fill in the blank status because it simply requires creation of “an established procedure”. The changes to 2.1.3 and 2.4.3 in addition to 1.1.2 appear to create circular logic to require Planners to know the seriousness of the consequences of a scenario they have yet to study.

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

**Douglas Johnson - American Transmission Company, LLC - 1**

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|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

We propose the following changes to Part 1.1.2, “Known outage(s) of generation or Transmission Facility(ies) planned to occur in the Near-Term Transmission Planning Horizon for applicable system conditions and year(s) selected by the Transmission Planner or Planning Coordinator for analyses . . .”:

- We suggest replacing the term, “scheduled”, with the words, “planned to occur”, because the term “scheduled” can be misinterpreted to apply only to outages that are approved and scheduled by Reliability Coordinators. On the other hand, the word “planned to occur” can refer to outages that TPs and PCs know need to be assessed in the planning horizon to implement identified Corrective Action Plans and Facility rebuilds, or know may be difficult or impossible to schedule in the operating horizon without the risk of exceeding System Operating Limits or risk of Non-Consequential Load Loss.

If the term “scheduled” is not replaced and is interpreted to apply only to outages that are approved and scheduled by Reliability Coordinators, then the NERC proposed Part 1.1.2.1 should be removed because Reliability Coordinators only approve scheduled outages in the planning horizon after they assessed for acceptable reliability impact for the applicable system conditions of the outage. So, there is no need to require Planning Coordinators and Transmission Planners to duplicate the assessment of the Reliability Coordinator’s scheduled outages.

- We suggest adding, “for applicable system conditions and year (s)”, to make clear that the selected outages are related to specific timeframes and are not ‘hypothetical’ outages.

- We suggest replacing “Transmission Planner and Planning Coordinator” with “Transmission Planner or Planning Coordinator” because each entity may have valid documented procedures or technical rationale for selecting appropriate outages that differ due to their specific perspectives and roles.

We propose replacing Part 1.1.2.1 with previous proposed wording of, “Are selected in accordance with documented outage selection procedures or technical rationale”. If this wording in not added to Part 1.1.2.1, then Part 1.1.2.1 is not a selection limiting criteria. All known outages would have to be evaluated to determine whether any of them are expected to result in Non-Consequential Load Loss for P1 events in Table 1. And since all known outages were studies, then Part 2.1.3 and Part 2.4.3 would have already been performed without any known outage selection limitations.

Furthermore, the proposed Part 1.1.2 text does not address FERC’s directive for “NERC to modify Reliability Standard TPL-001-4 to address the concern that the standard could exclude planned maintenance outages of significant facilities from future planning assessments…” [FERC Order 786, Final Rule, Item 3, page 5; Planned Maintenance Outages, pp. 29-37].

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

**Mike Smith - Manitoba Hydro - 1, Group Name** Manitoba Hydro

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| **Answer** | No |
| **Document Name** | |

**Comment**

The changes meet the FERC directive but is restrictive on the transmission Planner/Planning Coordinator. In TPL-001-4, only outages 6 months or greater in the Planning Horizon needed to be considered. Requirement R1.1.2.2, as now written, does not permit exclusion solely based on outage duration, which means even one day or one hour outages that are in the near-term Planning horizon cannot be excluded. Perhaps the drafting can consider permitting exclusion of known outages based on some minimum duration (eg. outages less than 1 month maybe excluded, outages between 1 and 6 months may only be excluded if they are not expected to result in non-consequential load loss for P1 events, all outages greater than 6 months shall be included). This makes expectations more clear and avoids the need to develop a technical rationale.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Ellen Oswald - Midcontinent ISO, Inc. - 2**

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|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

We propose the following changes to Part 1.1.2, “Known outage(s) of generation or Transmission Facility(ies) planned to occur in the Near-Term Transmission Planning Horizon for applicable system conditions and year(s) selected by the Transmission Planner or and Planning Coordinator for analyses . . .”:

We suggest replacing the term, “scheduled”, with the words, “planned to occur”, because the term “scheduled” can be misinterpreted to apply only to outages that are approved and scheduled by Reliability Coordinators. On the other hand, the word “planned to occur” can

- refer to outages that TPs and PCs know need to be assessed in the planning horizon to implement identified Corrective Action Plans and Facility rebuilds, or know may be difficult or impossible to schedule in the operating horizon without the risk of exceeding System Operating Limits or risk of Non-Consequential Load Loss.

If the term “scheduled” is not replaced and is interpreted to apply only to outages that are approved and scheduled by Reliability Coordinators, then the NERC proposed Part 1.1.2.1 should be removed because Reliability Coordinators only approve scheduled outages in the planning horizon after they assessed for acceptable reliability impact for the applicable system conditions of the outage. So, there is no need to require Planning Coordinators and Transmission Planners to duplicate the assessment of the Reliability Coordinator’s scheduled outages.

- We suggest adding, “for applicable system conditions and year (s)”, to make clear that the selected outages are related to specific timeframes and are for real applicable system conditions.

- We suggest replacing “Transmission Planner and Planning Coordinator” with “Transmission Planner or Planning Coordinator” because each entity may have valid documented procedures or technical rationale for selecting appropriate outages that differ due to their specific perspectives and roles.

We propose replacing Part 1.1.2.1 with previous proposed wording of, “Are selected in accordance with documented outage selection procedures or technical rationale”. If this wording in not added to Part 1.1.2.1, then Part 1.1.2.1 is not a selection limiting criteria. All known outages would have to be evaluated to determine whether any of them are expected to result in Non-Consequential Load Loss for P1 events in Table 1. And since all known outages were studies, then Part 2.1.3 and Part 2.4.3 would have already been performed without any known outage selection limitations.

Furthermore, the proposed Part 1.1.2 text does not address FERC's directive for "NERC to modify Reliability Standard TPL-001-4 to address the concern that the standard could exclude planned maintenance outages of significant facilities from future planning assessments…" [FERC Order 786, Final Rule, Item 3, page 5; Planned Maintenance Outages, pp. 29-37].

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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| **Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| MEC supports NSRF comments. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| NVE recommends that R1.1.2 be modified to include outages that span the season being studied. For outages in the season being studied that are less than the entire span of the season, the Transmission Planner should be able to select which outage to study based on when in the study season the outage is to occur and the significance of the generation or transmission facilities involved in the outage for the area of the system they are located in. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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| **Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name** OKGE | |
| **Answer** | No |

| Document Name | |
|---|---|
| **Comment** | |

OG&E recommends the drafting team add clarifying language to subparts 2.1.3 and 2.4.3 that specifies how the PC and TP should assess and run the required studies.

Recommendation:

The following revised language for subparts 2.1.3 and 2.4.3 will provide clarity and eliminate ambiguity how analysis is performed with respect to the subparts previously mentioned (see as follow):

**Subpart 2.1.3 (Proposed language)**

"P1 events in Table 1 expected to produce more severe System impacts on its portion of the Bulk Elextric System (BES), with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions, **as selected in Part 2.1.1 and 2.1.2**, when known outages are scheduled."

**Subpart 2.4.3 (Proposed language)**

"P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions, **as selected in Part 2.4.1 and 2.4.2**, when known outages are scheduled."

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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**Quintin Lee - Eversource Energy - 1, Group Name** Eversource Group

| **Answer** | No |
|---|---|
| **Document Name** | |
| **Comment** | |

Comments: Other options could better address concerns in the FERC directive order No 786. The requirement to study outages of any duration in the Near Term Planning Horizon creates burden on the planning process to address the scheduling of outages rather than adequacy of BES infrastructure. Transmission planning is expected to determine performance deficiencies of the system and to mitigate them with planning solutions. Studying impacts of outages with 2 independent unplanned events on top of it would require the creation of additional base cases for (1) each outage in the 1-5 year horizon, or (2) creating cases which encompass all anticipated outages in a season. Next, one would then need to perform all analyses on top of such outages that would be included in the base cases. This essentially creates another layer of contingency analysis which can result in selective N-1-1-1 or more events deep depending on the method used. The results would likely be that impacts could be mitigated by: (a) scheduling appropriately to ensure outages do not overlap, or (b) moving outages into different seasons.

Unintended consequences could result. One example, although unlikely, would be proposing the construction of a transmission project that is built to allow for an outage of a facility for maintenance/rebuild which may be a rare outage occurrence itself. This project just adds a selective 3rd layer of transmission redundancy to the system to allow for reliable system operation during an outage if up to 2 other unplanned events occurred. While this exercise may be of importance to the scheduling of outages and identification of impacts of outages and contingencies, it is best handled by operations planning (operating horizon) which should instead handle the study and scheduling of planned outages beyond the operating horizon and into the Near Term Planning.

Alternative Draft wording for Requirement 1, Part 1.1.2 is provided below.

**1.1.2**. Known outage(s) of generation or Transmission Facility(ies) scheduled in the Near-Term Transmission Planning Horizon selected for analyses pursuant to Requirement R2, Parts 2.1.3 and 2.4.3 only. Known outage(s) shall be selected according to an established procedure or technical rationale that, at a minimum:

**1.1.2.1.** Includes known outage(s) that are expected to result in Non-Consequential Load Loss for P1 events in Table 1 when concurrent with the selected known outage(s);

**1.1.2.2.** Considers outage duration(s) but does not exclude known outage(s) solely based upon their duration;

**1.1.2.3.** Considers the significance of the generation and Transmission Facility(ies) involved in the known outage(s) for the area of the system in which they are located; and

**1.1.2.4.** Considers the expected load levels during the known outage(s).

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6**

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| **Answer** | No |
| **Document Name** | |

**Comment**

NIPSCO believes any potential issues associated with planned maintenance outages are best identified through operational studies such as real time, next-day, and seasonal analysis rather than through the annual TPL-001-4 system performance analysis. Planned maintenance outages are almost always of short duration and are commonly scheduled to avoid occurrence during critical peak seasons. Only planned maintenance outages which are reasonably expected to occur during critical peak seasons, such as those six months or longer, should be included in the annual TPL-001-4 system performance analysis.

Removing the existing six month threshold for planned maintenance outages and continually reducing the time of duration requires the analysis of an ever greater number of concurrent generator and line outages beyond any specified in the TPL-001-4 standard including (P2) bus+breaker fault, (P4) stuck breaker, and (P7) common tower. This moves the performance analysis requirements of the TPL-001-4 standard closer to an effective N-2 requirement, which is currently an Extreme event, which was never intended.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Russel Mountjoy - Midwest Reliability Organization - 10, Group Name** MRO NSRF

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|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

We suggest replacing the term, “scheduled”, with the words, “planned to occur”, because the term “scheduled” can be misinterpreted to apply only to outages that are approved and scheduled by Reliability Coordinators. On the other hand, the word “planned to occur” can

- refer to outages that TPs and PCs know need to be assessed in the planning horizon to implement identified Corrective Action Plans and Facility rebuilds, or know may be difficult or impossible to schedule in the operating horizon without the risk of exceeding System Operating Limits or risk of Non-Consequential Load Loss.

If the term “scheduled” is not replaced and is interpreted to apply only to outages that are approved and scheduled by Reliability Coordinators, then the NERC proposed Part 1.1.2.1 should be removed because Reliability Coordinators only approve scheduled outages in the planning horizon after they assessed for acceptable reliability impact for the applicable system conditions of the outage. So, there is no need to require Planning Coordinators and Transmission Planners to duplicate the assessment of the Reliability Coordinator’s scheduled outages.

- We suggest adding, “for applicable system conditions and year (s)”, to make clear that the selected outages are related to specific timeframes and are for real applicable system conditions.
- We suggest replacing “Transmission Planner and Planning Coordinator” with “Transmission Planner or Planning Coordinator” because each entity may have valid documented procedures or technical rationale for selecting appropriate outages that differ due to their specific perspectives and roles.

We propose replacing Part 1.1.2.1 with previous proposed wording of, “Are selected in accordance with documented outage selection procedures or technical rationale”. If this wording in not added to Part 1.1.2.1, then Part 1.1.2.1 is not a selection limiting criteria. All known outages would have to be evaluated to determine whether any of them are expected to result in Non-Consequential Load Loss for P1 events in Table 1. And since all known outages were studies, then Part 2.1.3 and Part 2.4.3 would have already been performed without any known outage selection limitations.

Furthermore, the proposed Part 1.1.2 text does not address FERC’s directive for “NERC to modify Reliability Standard TPL-001-4 to address the concern that the standard could exclude planned maintenance outages of significant facilities from future planning assessments…” [FERC Order 786, Final Rule, Item 3, page 5; Planned Maintenance Outages, pp. 29-37].

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name** Lincoln Electric System

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

The phrase “expected to result” in Part 1.1.2.1 seems to imply that an entity must have studied the known outages to have an expectation of whether or not Non-Consequential Load Loss may occur. LES recommends the following alternate wording to Part 1.1.2.1: “Includes known outage(s) that **in qualified past studies have** resulted in Non-Consequential Load Loss for P1 events in Table 1…”

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

**Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name** Chelan PUD

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|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

R1.1.1.2 requires planners to include known generation and transmission facility outages scheduled within the Near-Term Transmission Planning Horizon and to select the outages studied according to an established procedure or technical rationale. The requirement also states that outages should not be excluded solely based on outage duration. FERC Order 786 states that acceptable approaches for addressing the outage concern include decreasing the threshold to fewer months or including parameters for identifying “significant planned outages” (page 33).

Planners should review planned outages for the season under study and use technical rationale to determine whether an outage should be included or excluded from the study. Per FERC Order 786, planners should have the flexibility to exclude outages based on their technical rationale. Outages not deemed significant for the TPL assessment will be included in operations studies as the outage approaches.

CHPD has three concerns related to this proposed language regarding known outages in R1.1.2.:

1. The nature of the outage, i.e. scope of work, has an effect on the system but the transmission planners do not necessarily know how a facility will be removed from service. For example, for maintenance of a relay system, there are many options for performing the maintenance with impacts ranging from delayed clearing to no system impact at all: 1) simply take the maintenance outage with all other systems energized (relying on delayed clearing); 2) take the local terminal out of service (likely eliminating the delayed clearing risk); or 3) bypass the normal breaker and relays and feed the line from a bus tie or transfer breaker. CHPD requests the standard provide coordinators with flexibility to assume the scope and nature of outages.

2. For overlapping, un-coordinated outages, the Planning Authority or Transmission Planner should be given authority to, when appropriate, move the outages for the purposes of the planning study so they do not overlap. This activity is frequently performed for outages in the Operations Timeframe, but no construct exists to do this for outages in the Planning Horizon. The proposed Standard should provide such a construct.

3. For situations in which new infrastructure for a Corrective Action Plan cannot be built prior to an outage, e.g., an outage scheduled in 1.5 years requires a capital project that will take 3 years to build, the proposed Standard should allow for the interruption of firm transmission service. FERC’s concern was that properly planned outages should not lead to load shedding. FERC Order 786, paragraph 41. Allowing for interruption of firm transmission will allow critical outages to be taken while avoiding non-consequential load loss.

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| Likes 0 | |

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| Dislikes 0 | |
| **Response** | |
| | |
| **Bridget Silvia - Sempra - San Diego Gas and Electric - 3** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

These are planning studies, not operating studies. Outage coordination studies are currently done by the operations department as part of operations seasonal planning. Adding outage coordination studies to the Near Term Planning Horizon [1-5 years] will increase the planning work load without any real reliability improvement. The reason being that planned outages are currently part of transmission planning in both the Near and Long Term Horizons. It is a matter of understanding the steady-state contingency results. When looking at future system behavior, N-2 steady-state contingency analysis will reveal system performance with a single BES element out of service followed by a P1 event. Two element are out of service N-2. This is only a starting point. When N-2 contingency analysis does not show any performance violations, the system should be able to remove BES elements from service without issue. If a performance violation is found, then further analysis is required (N-1-1).  We do not need a new requirement.

If the requirement is added, the stability portion should be removed.  Including stability analysis to the requirement will make it overly burdensome and will not improve reliability. Stability analysis software is not well suited for automation and the TPs and PCs can not reasonably be expected to perform stability analysis for every valid P1 contingency for each possible BES outage. The language of the requirement calls for contingencies which are “expected to produce more serverer system impacts”. The only way to know the expected stability impact is to study it. Therefore, the requirement actually requires all planned outages to be studied using stability analysis and then to use those results to support the selection of a contingency subset to be studied. This is a circular argument. Stability analysis of planned is not needed for reliability.

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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| **Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

Tri-State partially agrees but has some reservations regarding the specific language and overlaps with existing P3 and P6 contingency  categories.

Requirement 1.1.2.2 runs counter to Requirement 1.1.2 which allows outage selection based on technical rationale. Technical rationale would include time-dependence. The inclusion of major outages regardless of time duration effectively adds an outage coordination aspect to performing the TPL assessment. Outage coordination is already performed by Transmission Operations.

Requirement 1.1.2 effectively describes a category P3 or P6 contingency.

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| Likes 0 | |
| Dislikes 0 | |

| Response | |
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| **Kelsi Rigby - APS - Arizona Public Service Co. - 5** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| AZPS respectfully asserts that the proposed criteria under Requirement R1, Part 1.1.2 presents an overly complicated response to the Commission's directive in Order 786, Paragraph 43. Specifically, the Commission's directive allowed for the response to the directive to be a simple reduction of the 6 month time period. Such reduction would provide objective criteria for the entire industry to utilize to determine whether or not planned outages should be included in their planning assessment. AZPS is concerned that the proposed criteria under Part 1.1.2 is subjective in nature and could result in the potential for inconsistency relative to the inclusion of outages in planning assessments, e.g., outages of three (3) months or less could be implicated by some entities despite such outages creating unnecessary study burden with little to no reliability benefit wherein other entities could exclude such short-term outages.<br><br>To ensure that the criteria provides more objectivity relative to the inclusion of outages in planning assessments, which would increase the overall consistency and value of planning assessments generally, AZPS recommends that the SDT reconsider the currently proposed criteria and replace it with criteria that requires outages to be included where such outages meet a definitive time period of "more than 3 months." AZPS respectfully asserts that short term outages should be studied and prepared for in the Operating horizon and not in a planning assessment and, further, that the potential for inconsistency between planning assessments would reduce the proposed reliability benefit anticipated by the currently proposed criteria. For these reasons, AZPS recommends replacement of the currently proposed criteria with a simplified criteria requiring inclusion of outages that are anticipated to last more than three months. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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| **Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| BPA appreciates that the reference to consultation with the Reliability Coordinator has been removed and that "Transmission" was added to Near-Term Transmission Planning Horizon.<br><br>For R1.1.2.2 BPA does not believe it would be reasonable to require justification for every known outage that is not included. The way R1.1.2 is written, it seems to imply that an outage excluded based on duration should also not meet the established procedure or technical rationale. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

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|---|---|
| **John Seelke - LS Power Transmission, LLC - 1** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

The language in Part 1.1.2 is fine; however the language added to R2 Parts 2.1.3 and 2.4.3 that is referenced in Part 1.1.2 is confusing. Page 8 of the posted Technical Rationale document contains the rationale for changes to R2 Parts 2.1.3 and 2.4.3:

"Consistent with FERC's directive, the drafting team modified Requirements **R2 Parts** 2.1.3 and 2.4.3 to further recognize the intent to limit required study to only those known outages that are expected to produce severe System impacts on the PC/TP's respective portion of the BES."

LSPT agrees with this rationale. However, the changes to Parts 2.1.3 and 2.4.3 do not accomplish this objective. Since both 2.1.3 and 2.4.3 have the same added language, the concern is illustrated in 2.1.3 only, which states the following regarding the analysis required by the Planning Coordinator or Transmission Planner, with the added language bolded:

**2.1.3.** P1 events in Table 1 **expected to produce more severe System impacts on its portion of the BES**, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

The proposed change allow the PC/TP to **not** evaluate all P1 events; the PC/TP must only evaluate those P1 events in Table 1 "expected to produce the most severe System impacts on it portion of the BES." In other words, the P1 events in combination with "known outages" that produce the most severe System impacts may be a different set of P1 events..

LSPT's proposed changes to 2.1.3 (and correspondingly to 2.4.3) will correct this unintended consequence:

**2.1.3.** P1 events in Table 1, with known outages **that are expected to produce more severe System impacts on its portion of the BES** modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled.

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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| **Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 6** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

We understand the need to address FERC Order No 786; however, the additions to 1.1.2 are creating additional unnecessary modeling work that we do not believe provides additional value to reliability.

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| Likes 0 | |
| Dislikes 0 | |

| Response |  |
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| **Hasan Matin - Orlando Utilities Commission - 2 - FRCC** |  |
| **Answer** | No |
| **Document Name** |  |
| **Comment** |  |

OUC believes the proposed Requirement 1.1.2. leaves too large of ambiguity in what needs to be tested. The intent of what is required to be tested is not clear, and appears on the surface to overlap significantly with the Operations Planning realm. The current standards provide enough parameters to include outages into the base case (using the 6 month outage duration as a threshold). The proposed changes reads as if it's requiring long-term transmission planners to study operational planning studies under the "Near-Term Transmission Planning Horizon". OUC does not believe the TPL requirements should include operational planning studies that should otherwise be included under the TOP standards (i.e. TOP-002-4). By not defining an outage duration, the requirement now appears to welcome any and all outage scenario testing, which should otherwise be completed under the TOP standards. Although Requirement 1.1.2.1 was added to limit the outages selected, for most it would be unclear what scenarios would result in non-consequential load loss, thus not providing enough of a parameter to limit the outages needed to be tested.

Suggestion: OUC would suggest keeping the outage length as a parameter in order to filter the outages that should be studied in the Near-Term Planning Horizon. In understanding the 6 month outage duration not being inclusive of what the drafting team may be looking for, perhaps limiting the outage duration to 3 months would include enough of the key outages that should be studied, while not including all outages which would otherwise need to be analyzed under Operations Planning scenarios.

| Likes 0 |  |
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| Dislikes 0 |  |
| **Response** |  |
|  |  |
| **Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6** |  |
| **Answer** | No |
| **Document Name** |  |
| **Comment** |  |
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| Likes 0 |  |
| Dislikes 0 |  |
| **Response** |  |
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| **David Jendras - Ameren - Ameren Services - 3** |  |

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|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

As proposed, we believe that R1.1.2.1 involves the creation of hypothetical outages to evaluate and include in the transmission assessment.

From the Order 786, paragraph 42, "The Commission's directive is to include known generator and transmission planned maintenance outages in planning assessments, not hypothetical planned outages." Most transmission maintenance outages are scheduled in the operating horizon, after considerable review and analysis of expected system conditions in the operating horizon. These outages may be daily, weekly, or of longer duration, but still they are planned and scheduled in the operating horizon and not the planning horizon. Therefore, from a planning perspective, few if any transmission outages will be included in the base case peak or off-peak models for analysis and development of the Planning Assessment because these maintenance outages have not been scheduled in the planning horizon.

The Commission goes on to state in paragraph 44 that "these potential planned outages must be addressed, so long as their planned start times and durations may be anticipated as occurring for some period of time during the planning time horizon". In other words, the Commission wants us to speculate on the start and stop times of the maintenance outages, effectively creating hypothetical outages to consider for analyses. From our perspective the language of this paragraph of Order 786 is ambiguous.

The Commission also stated in paragraph 44 that category P3 and P6 contingencies do not cover generation and transmission maintenance outages, but during the webinar, it was suggested by a member of the standard drafting team that the allowance of system adjustments following the planning maintenance outage event was the reason for FERC's disapproval. Is it the drafting team position that if the analyses were performed without system adjustments between the outage events, then FERC would not object? We did not read that response in Order 786 and request that the Standard Drafting Team provide reference that analyses of P3 and P6 events without system adjustment, other than make-up power, would provide an acceptable method for determining system adequacy during maintenance, planned or hypothetical, outages. However, we question why generation redispatch or other operating guides cannot be developed, if needed, to facilitate the performance of maintenance outages in the planning or operating horizons.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF**

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| **Answer** | No |
| **Document Name** | |

**Comment**

Requirement 1, Part 1.1.2.1., does not provide a clear demonstrable criterion for outage selection. In order to conclusively determine “expected” Non-Consequential Load Loss during an N-2 event, studies must be performed to determine the response of the system. Therefore, this requirement, as written, implies that the Transmission Planner must consider *all* known outages. In Order 786, paragraph 43, FERC suggested that a selection parameter of facility ratings could be used. Use of a facility rating threshold in the standard would provide needed clarity to Transmission Planners and result in greater consistency.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Jamie Monette - Allete - Minnesota Power, Inc. - 1**

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|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Seattle City Light - 5 - WECC**

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|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Shawn Abrams - Santee Cooper - 1**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

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| Likes 0 | |
| Dislikes 0 | |

**Response**

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|---|---|
| **Richard Vine - California ISO - 2** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| The California ISO agrees with the changes in Part 1.1.2 with the exceptions noted in the response to Question 4 below. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| There is no one size fits all country wide method of identifying which known outages are best included in this section. The SDT has put in place a mechanism that allows reasonable local tailoring to the list of known outages by the TP or PC. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Robert Ganley - Long Island Power Authority - 1** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| Section 2.7, related to Corrective Action Plans – there appears to be an incorrect reference to Section 2.4.3. This reference should be changed to the new section 2.4.4 | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

**Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2**

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|---|---|
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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**Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC**

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| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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**Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name** RSC no Hydro One, NYISO and Eversource

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| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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**Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1**

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|---|---|
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name** PPL NERC Registered Affiliates | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Dennis Sismaet - Northern California Power Agency - 6** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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| **faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6** | |

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|---|---|
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Marty Hostler - Northern California Power Agency - 5** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Fred Frederick - Southern Indiana Gas and Electric Co. - 3** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Jeff Landis - Platte River Power Authority - 3** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |

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|---|---|
| Dislikes 0 | |
| **Response** | |
| | |
| **Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Joe McClung - JEA - 3,5 - FRCC, Group Name** JEA Voters | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 1 | JEA, 5, Babik John |
| Dislikes 0 | |
| **Response** | |
| | |
| **John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC** | |
| **Answer** | Yes |

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|---|---|
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Jeffrey DePriest - DTE Energy - Detroit Edison Company - 3,4,5, Group Name** DTE Electric | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

**3. Do you agree with the proposed implementation plan?**

| | |
|---|---|
| **Joe McClung - JEA - 3,5 - FRCC, Group Name** JEA Voters | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

The 36-months period for the proposed standard to become effective seems to be adequate along with an additional 24-months period for the development of CAP for the newly identified issues only with new P5.

However, we do not agree with the overall Implementation Plan. The P8 event proposal is out of scope based on our response for Q1. Therefore, JEA does not agree with the development of CAP for P8 either. There should not be a performance requirement for an extreme event and hence no CAP needs to be mandated. If the analysis for the extreme events with the clarified Footnote 13 with the single points of failure concludes there is Cascading, the PCs and TPs shall conduct an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences. This is already required today for compliance with the Requirement R2 sub-requirement 4.5 of TPL-001-4. Any development of CAP and its implementation plan for such an extreme event should be at the discretion of the individual entities.

We agree with the performance requirements for the updated P5 event. However, we do not agree with the 96-months period to meet the performance requirements for the newly identified issues with the proposed P5 events. As the SDT has acknowledged, the only way to meet the performance requirements for P5 events with single points of failure in Protection System will mostly be a capital improvement project to be installed at the identified substation(s). Even though performing the studies/analyses and the development of CAPs are within PCs' and TPs' control, they do not have any control in implementing the CAPs. The amount of capital improvement budget available, the outage coordination amongst various parties (GO, GOP, TO, TOP, system operators and even RCs), project scheduling as well as the availability of manpower to actually implement the CAPs at the substations with a sudden influx of work outside the routine job are numerous facets of the project implementation beyond the control of PCs and TPs. The size of the utility and the number of CAPs to be implemented can create additional different challenges for different types of utilities such as co-ops, municipals, IOUs etc. in different regions/markets (ISO/RTO/vertically integrated etc.)

**Suggestion**: Remove the proposed P8 event along with the associated CAP and the Implementation Plans. For the new CAPs with the newly-added studies for P5 planning events only with single points of failure on Protection System, JEA recommends for NERC to survey the industry (PCs, TPs and Facility owners) with another **Request for Data Under Section 1600 of the NERC Rules of Procedure** for a more realistic implementation schedule. Or alternatively, request and track the implementation plans for CAPs for such P5 events from the industry as part of the annual **ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP)**.

| | |
|---|---|
| Likes 1 | JEA, 5, Babik John |
| Dislikes 0 | |
| **Response** | |
| | |
| **Jeff Landis - Platte River Power Authority - 3** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

PRPA supports JEA comments.

The 36-months period for the proposed standard to become effective seems to be adequate along with an additional 24-months period for the development of CAP for the newly identified issues only with new P5.

However, we do not agree with the overall Implementation Plan. The P8 event proposal is out of scope based on our response for Q1. Therefore, JEA does not agree with the development of CAP for P8 either. There should not be a performance requirement for an extreme event and hence no CAP needs to be mandated. If the analysis for the extreme events with the clarified Footnote 13 with the single points of failure concludes there is Cascading, the PCs and TPs shall conduct an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences. This is already required today for compliance with the Requirement R2 sub-requirement 4.5 of TPL001-4. Any development of CAP and its implementation plan for such an extreme event should be at the discretion of the individual entities.

We agree with the performance requirements for the updated P5 event. However, we do not agree with the 96-months period to meet the performance requirements for the newly identified issues with the proposed P5 events. As the SDT has acknowledged, the only way to meet the performance requirements for P5 events with single points of failure in Protection System will mostly be a capital improvement project to be installed at the identified substation(s). Even though performing the studies/analyses and the development of CAPs are within PCs' and TPs' control, they do not have any control in implementing the CAPs. The amount of capital improvement budget available, the outage coordination amongst various parties (GO, GOP, TO, TOP, system operators and even RCs), project scheduling as well as the availability of manpower to actually implement the CAPs at the substations with a sudden influx of work outside the routine job are numerous facets of the project implementation beyond the control of PCs and TPs. The size of the utility and the number of CAPs to be implemented can create additional different

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challenges for different types of utilities such as co-ops, municipals, IOUs etc. in different regions/markets (ISO/RTO/vertically integrated etc.)

Suggestion: Remove the proposed P8 event along with the associated CAP and the Implementation Plans. For the new CAPs with the newly-added studies for P5 planning events only with single points of failure on Protection System, JEA recommends for NERC to survey the industry (PCs, TPs and Facility owners) with another Request for Data Under Section 1600 of the NERC Rules of Procedure for a more realistic implementation schedule. Or alternatively, request and track the implementation plans for CAPs for such P5 events from the industry as part of the annual ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP).

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Russel Mountjoy - Midwest Reliability Organization - 10, Group Name** MRO NSRF | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

Based on our preliminary review and our existing resources, the amount of time needed to develop new contingencies and perform new studies for new 'known outages' and 'non-redundant' Protection System components requirements will require substantially more time than the 36-month timeframe proposed in the implementation plan. So, we propose that the 36-month timeframe to perform these tasks be extended to a 60-month timeframe.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

| | |
|---|---|
| **Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| Should be 2 years longer. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Marty Hostler - Northern California Power Agency - 5** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| See JEAs response. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| We are not in agreement with the changes, therefore the implementation dicussion is a mute point at this time. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Dennis Sismaet - Northern California Power Agency - 6** | |

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| Please see JEA's comments. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| MEC supports NSRF comments. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Ellen Oswald - Midcontinent ISO, Inc. - 2** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| Based on our preliminary review and our existing resources, the amount of time needed to develop new contingencies and perform new studies for new ‘known outages’ and ‘non-redundant’ Protection System components requirements will require substantially more time than the 36-month timeframe proposed in the implementation plan. So, we propose that the 36-month timeframe to perform these tasks be extended to a 60-month timeframe. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Douglas Johnson - American Transmission Company, LLC - 1** | |
| **Answer** | No |

| | |
|---|---|
| **Document Name** | |
| **Comment** | |

Based on our preliminary review and our existing resources, the amount of time needed to develop new contingencies and perform new studies for new 'known outages' and 'non-redundant' Protection System components requirements will require substantially more time than the 36-month timeframe proposed in the implementation plan. So, we propose that the 36-month timeframe to perform these tasks be extended to a 60-month timeframe.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

**Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

Duke Energy does not agree with the proposed Implementation Plan. Depending on system conditions, it is anticipated that when using Dynamic Load Modeling, that an entity could see a great number of its Facilities fail the performance requirements. Failure of the performance requirements could result in significant upgrades, which take time to implement. With the potential for significant upgrades to a majority of applicable Facilities, Duke Energy cannot agree with the Implementation Plan proposed.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

**John Bee - Exelon - 3**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

See Exelon TO Utilities Comments

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

**Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken**

| | |
|---|---|
| **Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name** FMPA | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| FMPA supports the comments of JEA on the implementation plan. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| Based on our preliminary review and our existing resources, the amount of time needed to develop new contingencies and perform new studies for new 'known outages' and 'non-redundant' Protection System components requirements will require substantially more time than the 36-month timeframe proposed in the implementation plan. So, we propose that the 36-month timeframe to perform these tasks be extended to a 60-month timeframe. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name** PPL NERC Registered Affiliates | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| Louisville Gas and Electric Company and Kentucky Utilities Company (LKE) supports providing Planning Coordinators (PCs) and Transmission Planners (TPs) 36 months until the effective date of the Standard to develop a procedure or technical rationale for selecting known outages of generation and Transmission Facilities, a process for establish coordination with protection engineers to obtain the necessary data to perform the single points of failure analysis, and additional base case models and analysis. However, LKE believes that requiring "the planned System [to] continue to meet the performance requirements in Table 1 until 96 months after the effective date of Reliability Standard TPL-001-5" is too long. The three years before the effective date plus 8 years is 11 years. Other NERC standards do not have an 11 year time frame to fix an identified reliability risk to the BES. | |

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

See comments from MRO NSRF.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6; - Michael Brytowski**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

GRE agrees with the MRO NSRF comments.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Robert Ganley - Long Island Power Authority - 1**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

Since we have concerns with the ambiguity of the proposed P8 event (see our comments to question #1), we feel it is premature to consider a specific implementation plan that involves that event. We cannot agree to a proposed implementation plan for an event that needs clarification.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

| Response | |
|---|---|
| | |
| **Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

KCP&L recommends extending to 60-months the preparation period prior to the effective date of the Standard.

In the alternative, provide flexibility or a process to extend the 36-month period based on the TP and PC's evaluation to implement the revised TPL-001-5 Standard.

**Concern**

The proposed Implementation Plan's time periods do not fully consider the differences in system sizes, complexity, and design elements.

Additionally, with the Standard's assessment scope expansion, the periods offered in the Plan need to consider barriers entities face staffing or contracting for the qualified personal to complete studies and implement CAPs.

KCP&L identified activities it anticipates will be required under the Standard that make the Plan's time periods insufficient to complete implementation of the proposed Standard. Here is an example:

- Changing and updating contingency lists will extend beyond the 36-month period because of the complexity and size of the undertaking and required vetting.

Beyond a single implementation activity, the implementation of the revised Standard will require long-duration, contingent, inter-related activities that, taken individually may fall within the 36-month period but, to collectively complete all the activities, will extend beyond the 36-month period. For example:

1. The best-case scenario to update and test dynamics software will take at least 12-months. The estimated period is without consideration of challenges to:

- Schedule the software upgrade and testing;
- Incorporate the additional P8 events and the re-alignment of Extreme events into the software; and
- Address the many "small" changes that will affect the planning models and assessments.

The proposed revision's specific and required assessments are contingent on updating and testing dynamics software. The period to complete the upgrade and assessments we easily see extending beyond the 36-month proposed implementation period.

A 36-month period to complete required assessments seems arbitrary when placed against the wide spectrum of applicable systems. In consideration of system differences, we recommend the 60-month period or, in the alternative, a process to extend the period based on TP and PC's evaluation to implement the revised TPL-001-5 Standard.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

| Response | |
|---|---|
| | |
| **Rachel Coyne - Texas Reliability Entity, Inc. - 10** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

Texas RE appreciates the SDT's efforts in putting together the proposed Implementation Plan. Texas RE notes that, in its experience, registered entities have had significant issues understanding and following implementation plans. Texas RE therefore strongly encourages the SDT to carefully review the proposed Implementation Plan to ensure that is not ambiguous, vague, or confusing to understand.

To that end, Texas RE notes two aspects of the proposed implementation plan that could lead to potentially significant industry confusion. First, Texas RE notes that in establishing the requirement to complete planning assessments 36 months following the effective date of the standard approval, the proposed Implementation Plan is silent regarding the specific Standard Requirements that are actually implicated. Texas RE recommends that the SDT not merely rely on references to "planning assessments," but actually insert specific references to the Requirements subject to the 36-month planning assessment compliance threshold to reduce any possible ambiguity. Second, the proposed implementation plan provides that the requirement to implement Corrective Action Plans (CAPs) to be "the first calendar quarter 84 months following applicable regulatory approval of TPL-001-4." The effective date of the FERC Order approving TPL-001-4 is December 22, 2013. As such, the CAP requirement would, on its face, be due on March 1, 2020. Because TPL-001-5 will not become effective for at least 36 months following any applicable regulatory approvals, this requirement would trigger *prior* to the effective date of the proposed TPL-001-5 Standard. This appears to be in error, and Texas RE suggests that the SDT revise this aspect of the implementation plan accordingly – perhaps by inserting a reference to TPL-001-5 instead of TPL-001-4.

In addition to these issues, Texas RE presently understands the implementation plan, as currently drafted, to provide the following glide path to full implementation of the proposed TPL-001-5 Standard:

**First calendar quarter 36 months following regulatory approval**.

· The effective date of the standard is the first day of the first calendar quarter 36 months following the effective date of the applicable governmental authorities order approving the standard. This date serves as a starting point for the implementation plan.

· In accordance with the Initial Performance section, applicable entities must complete the planning assessment without CAPs by the effective date of the standard, or 36 months following the effective date of the applicable governmental authority's order approving the standard. Texas RE notes there is no requirement mentioned. In the interest of clarity and not being vague Texas RE strongly recommends the implementation plan specify which requirement this date refers to.

**60 months following regulatory approval**.

· In accordance with the Initial Performance section, applicable entities must develop any required CAPs under Requirement R2, Part 2.7 associated with the non-redundant components of a Protection System identified in Table 1 Category P5 Footnote 13, items b, c, and d, and P8 by 24 months following the effective date of the standard, or 36 months plus 24 months, or 60 months following the effective date of the applicable governmental authority's order approving the standard. Texas RE notes this is also indicated in the Compliance Date section.

**For 84 months following regulatory approval**

o Texas RE noted the issue with the standard version above in reference to the Note Regarding CAPs. Assuming this should indeed specify TPL-001-5, rather than TPL-001-4, CAPs applying to the specified categories of Contingencies and events identified in TPL-001-5, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Form Transmission Service.

**132 months following regulatory approval**

o In accordance with the Compliance Date section, entities have 96 months from the effective date to end the use of CAPs developed to address failures to meet Table 1 performance requirements for P5 and P8 events only. The way this is written indicates entities have 36 months following the effective date of the applicable governmental authorities order approving the standard *plus 96 additional months* to end the use of CAPs. Is it the SDT's intent that this be *132 months from the effective date of the applicable governmental authority's order*? This timeline seems excessively long and would unnecessarily burden registered entities to prove it is doing anything to support the reliable operation of the grid based on an assessment.

In addition to the two confusing aspects noted previously, Texas RE noticed additional areas in which this implementation plan lacks clarity.

· First, the implementation plan uses different but similar terms: Effective Date, Compliance Date, and Initial Performance Date. While implementation plans in the past have used Effective Dates to indicate the starting point at which all activities are based upon, the use of the Effective Date is inconsistent in this plan. The implementation plan calculates when applicable entities must do planning assessments from the effective date (must be by the effective date for planning assessments without CAPs) as well as it calculates when any required CAPs under Requirement R2, Part 2.7 associated with the non-redundant components of a Protection System identified in Table 1 Category P5 Footnote 13, items b, c, and d, and P8 must be developed (24 months following the effective date). It is *not* used to calculate the date by which applicable entities must end their use of CAPs, nor is it used to calculate the date by which CAPs should not include Non-Consequential Load Loss and/or curtailment of Firm Transmission Service (see Note Regarding CAPs). This date is calculated based upon the effective date of the applicable governmental authority's order. To improve clarity, the effective date should be used consistently.

· Texas RE inquires as to the difference between the terms Compliance Date and Initial Performance Date. The Compliance Date section contains the same information as the second paragraph of the Initial Performance section. Are they intended to mean two different things since two different terms are used?

· It is also unclear to which requirements the actions refer. Are we to assume that if the requirement is not mentioned specifically, it is enforceable on the effective date of the standard?

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller, Group Name** MEAG Power

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

| Comment | |
|---|---|
| The 36-months period for the proposed standard to become effective seems to be adequate along with an additional 24-months period for the development of CAP for the newly identified issues only with new P5.<br><br>However, we do not agree with the overall Implementation Plan. The P8 event proposal is out of scope based on our response for Q1. Therefore, We do not agree with the development of CAP for P8 either. There should not be a performance requirement for an extreme event and hence no CAP needs to be mandated. If the analysis for the extreme events with the clarified Footnote 13 with the single points of failure concludes there is Cascading, the PCs and TPs shall conduct an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences. This is already required today for compliance with the Requirement R2 sub-requirement 4.5 of TPL-001-4. Any development of CAP and its implementation plan for such an extreme event should be at the discretion of the individual entities.<br><br>We agree with the performance requirements for the updated P5 event. However, we do not agree with the 96-months period to meet the performance requirements for the newly identified issues with the proposed P5 events. As the SDT has acknowledged, the only way to meet the performance requirements for P5 events with single points of failure in Protection System will mostly be a capital improvement project to be installed at the identified substation(s). Even though performing the studies/analyses and the development of CAPs are within PCs' and TPs' control, they do not have any control in implementing the CAPs. The amount of capital improvement budget available, the outage coordination amongst various parties (GO, GOP, TO, TOP, system operators and even RCs), project scheduling as well as the availability of manpower to actually implement the CAPs at the substations with a sudden influx of work outside the routine job are numerous facets of the project implementation beyond the control of PCs and TPs. The size of the utility and the number of CAPs to be implemented can create additional different challenges for different types of utilities such as co-ops, municipals, IOUs etc. in different regions/markets (ISO/RTO/vertically integrated etc.)<br><br>Suggestion: Remove the proposed P8 event along with the associated CAP and the Implementation Plans. For the new CAPs with the newly-added studies for P5 planning events only with single points of failure on Protection System, We recommend NERC survey the industry (PCs, TPs and Facility owners) with another ***Request for Data Under Section 1600 of the NERC Rules of Procedure*** for a more realistic implementation schedule. Or alternatively, request and track the implementation plans for CAPs for such P5 events from the industry as part of the annual ***ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP)***. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name** Tennessee Valley Authority | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| TVA supports JEA's comments. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4** | |

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| See comments below. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| SCE expects that bullet D in the revised footnote 13 as currently written will bring over half of the existing SCE protection systems into scope for assessment of delayed clearing for P5 events. Without a completed assessment of the impact to reliability, SCE expects that some substations will require Corrective Action Plans to bring protection systems to full redundancy or system reliability within performance requirements. SCE proposes that the implementation plan keep the initial 36 months until Assessments must include the new models and studies but increase the time for developing Corrective Action Plans for P5 and P8 contingencies to an additional 60 months instead of 24. Similar to when TPL-001-4 first became effective, certain categories of contingencies were recognized as needing additional time for Transmission Planning entities to raise the bar on system performance. SCE proposes that the same latitude be applied to TPL-001-5's proposed higher standard of system performance. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name** Seattle City Light Ballot Body | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| City Light supports JEA comments. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| The implementation plan requires Oncor to perform contingency analysis for P8 contingencies and develop a Corrective Action Plan for any issues resulting from a P8 contingency. Oncor does not agree with the requirements pertaining to P8 contingencies as outlined in the first comment above. If the P8 contingency is adopted, the implementation time needs to be longer due to the effort required to gather the required information and perform the first analysis. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6 | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| Shawn Abrams - Santee Cooper - 1 | |
|---|---|
| **Answer** | No |

| | |
|---|---|
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Seattle City Light - 5 - WECC** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| The timeframes outlined in the implementation plan appear to be adequate to respond to the new requirements. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **David Jendras - Ameren - Ameren Services - 3** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |

| | |
|---|---|
| The implementation plan seems reasonable from a planning perspective. Depending on the number of system protection upgrades needed, the completion of these upgrades by the desired date may be a challenge. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 6** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| While we do not agree with the additional requirements, we believe 24 months is reasonable. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| None | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name** OKGE | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |

| | |
|---|---|
| References to P8 would need to be removed from the implementation plan if the proposed changes are made to move the P8 events back to Extreme Events. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Mike Smith - Manitoba Hydro - 1, Group Name** Manitoba Hydro | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| The implementation plan is ok other the plan associated with P8. Manitoba Hydro doesn’t agree that P8 should be added. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Neil Swearingen - Salt River Project - 1,3,5,6 - WECC** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| The Implementation Plan allows sufficient time to coordinate CAPs with external entities and meet compliance | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Jamie Monette - Allete - Minnesota Power, Inc. - 1** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |

| |
|---|
| **We agree with the implementation timeline, but the proposed revisions still need some work.We agree with the implementation timeline, but the proposed revisions still need some work.** |

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Jeffrey DePriest - DTE Energy - Detroit Edison Company - 3,4,5, Group Name** DTE Electric | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |

| Response | |
|---|---|
| | |
| **Hasan Matin - Orlando Utilities Commission - 2 - FRCC** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **John Seelke - LS Power Transmission, LLC - 1** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Kelsi Rigby - APS - Arizona Public Service Co. - 5** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC** | |
| **Answer** | Yes |
| **Document Name** | |

| | |
|---|---|
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name** Chelan PUD | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Fred Frederick - Southern Indiana Gas and Electric Co. - 3** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Quintin Lee - Eversource Energy - 1, Group Name** Eversource Group | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

| | |
|---|---|
| **Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Leonard Kula - Independent Electricity System Operator - 2** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Michael Jones - National Grid USA - 1, Group Name** National Grid | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| | |
|---|---|
| **Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name** RSC no Hydro One, NYISO and Eversource | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Richard Vine - California ISO - 2** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Brian Van Gheem - ACES Power Marketing - 6, Group Name** ACES Standards Collaborators | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name** SPP Standards Review Group | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Teresa Cantwell - Lower Colorado River Authority - 5** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name** Lincoln Electric System | |
| **Answer** | |
| **Document Name** | |
| **Comment** | |
| LES supports the comments provided by the MRO NERC Standards Review Forum (NSRF). | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| **Chris Scanlon - Exelon - 1, Group Name** Exelon Utilities | |
|---|---|
| **Answer** | |
| **Document Name** | |
| **Comment** | |
| On page 2 of the implementation plan, there is a statement in the third paragraph which may require some clarification. In "…failures to meet System performance requirements, identified during subsequent Planning Assessment(s), for single points of failure in Protection Systems may not be mitigated by an Operating Procedure during an interim period before a mitigating capital improvement is installed" does the phrase "may not be mitigated" imply that interim Operating Procedures will not be allowed, or is this an acknowledgement (and acceptance) that there may be instances in which an interim Operating Procedure may not be sufficient to meet the System performance requirements? We assume the second interpretation is what was intended, but it is recommended that this statement be clarified to eliminate the possibility of misinterpretation. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name** Southern Company | |
| **Answer** | |
| **Document Name** | |
| **Comment** | |
| The 60 month implementation plan is appropriate as a significant amount of protection and control related data and design drawings will have to be acquired and reviewed in order to facilitate the ability to study the required additional dynamic simulations. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

**4. Do you agree with the proposed revisions to TPL-001-4?**

| | |
|---|---|
| **Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

ERCOT would recommend two further revisions.

First, ERCOT recommends deleting requirement 1.1.2.1. This requirement is circular because one cannot know whether the known outage would result in Non-Consequential Load Loss when it occurs at the same time as a P1 event without performing the study in the first instance. Because this would effectively require one to study each P1 event combined with each known outage anyway, it would be simpler to delete 1.1.2.1 altogether while preserving 1.1.2.2 in order to directly address the relevant directive in FERC Order 786.

ERCOT recommends the following specific revisions based on the foregoing concerns:

1. Delete ", at a minimum:" from section 1.1.2 and replace with the full text of proposed 1.1.2.2 ("does not exclude known outage(s) solely based upon the outage duration.").

2. Delete sections 1.1.2.1 and 1.1.2.2.

Second, ERCOT recommends deleting the proposed additional language in requirements 2.1.3 and 2.4.3. This new language would clarify that the P1 events to be studied are those that are "expected to produce more severe System impacts on [the responsible entity's] portion of the BES." However, this is already permitted under requirement 3.4. This new proposed language is unnecessary and should be deleted.

ERCOT recommends the following specific revisions based on the foregoing concerns:

1. Delete proposed additional language "expected to produce more severe System impacts on its portion of the BES," from section 2.1.3.

2. Delete proposed additional language "expected to produce more severe System impacts on its portion of the BES," from section 2.4.3.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Teresa Cantwell - Lower Colorado River Authority - 5** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

See comments in response to question 2.

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|---|---|
| Likes 0 | |

| | |
|---|---|
| Dislikes 0 | |
| **Response** | |
| | |
| **Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

Oncor believes that the definition of 'non-redundant components of protection system' per Table 1, item 13 is consistent with FERC order 754 (2012) as well as NERC's technical paper on 'Redundancy of Protection System Elements' (2008) – However, this definition coupled with category P5 and newly added category P8 expands much beyond FERC Order 754 for the following reason:

- FERC Order 754 data request limited the buses to be analyzed by the voltage level and number of circuits associated with the bus. These criteria clearly were targeted to pick the more critical stations from reliability and stability stand point.
- The enforceable definition of the non-redundant protection scheme without general guidelines on where to apply such definition, in essence expands the assessment to the entire system without consideration to the criticality of the elements. Generally speaking, it is more common to have non-redundant schemes at smaller stations (lower kV, fewer transmission circuits, remote locations, etc.), as they have minimum system impacts during faults, and tend to have only localized issues (or outages that are not an issue).

Oncor recommends the assessments per category P5 and P8 should be limited to defined critical stations similar to FERC 0rder 754.

The redundancy as per Table 1-13(a) through Table 1-13(c) are reasonable replacement of 'relay failure' as per TPL-001-4. However, Oncor is not in agreement with Table 1-13(d) for the following reason:

In Oncor's experience, failure of DC control circuitry is an unlikely event in general. Additionally, if the circuits were to fail, the result would be a breaker failure (stuck breaker) resulting in operations of breaker failure schemes – avoiding remote delayed clearing which is much longer than breaker failure delay. Oncor believes this requirement is not sufficient justification to require assessing DC control circuitry.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Jamie Monette - Allete - Minnesota Power, Inc. - 1** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

**We agree with some of the revisions, but believe the establishment of a P8 event is not appropriate, the proposed criteria for including planned outages reaches too far into the Operating Horizon, and that Footnote 13 should be made clearer to avoid varying interpretations.**

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|---|---|
| Likes 0 | |

| | |
|---|---|
| Dislikes 0 | |

**Response**

**Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name** Seattle City Light Ballot Body

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

City Light supports JEA comments.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name** SPP Standards Review Group

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

The SPP Standards Review Group suggests restoring the language contained in the last draft (Sept. 2017 version) under Table 1 – Extreme Events – stability bullets 2e through 2h (but without the proposed 4.6 of draft 1 or the proposed 4.2.1 and 4.2.2 of draft 2). This revision will address the Commission's directive from Order No. 754 and is consistent with the recommendations from the Joint Report regarding the three phase faults.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Brian Van Gheem - ACES Power Marketing - 6, Group Name** ACES Standards Collaborators

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|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

1. We believe Requirement 2, Part 2.1.3 and Part 2.4.3 should complement our previous recommendation for Requirement 1, Part 1.1.2 on basing significant planned outages according to registered entity-selected facility ratings. The required studies should allow registered entities flexibility on which planned outages are necessary for P1 event studies, particularly those outages that incorporate Facility expansion, construction, or rebuilds and other solutions documented in Corrective Actions Plans.
2. The reference to open circuit within Footnote 13c needs further clarification. The term "dc supply" is ambiguous and needs to confirm the accepted configuration for substation control houses. Will this require two batteries, two separate battery chargers for a single battery bank, or

onsite backup generation as the accepted configuration? The technology currently available for detecting open circuits is problematic and can introduce addition points of failure when in service. We recommend clarifying the reference to read “A single station dc supply associated with protective functions required for Normal Clearing, and that single station dc supply is not monitored or not reported at a Control Center for abnormal DC voltages.”

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Richard Vine - California ISO - 2**

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|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

The California ISO generally agrees with the proposed revisions to TPL-001-4, but would recommend two revisions.

First, the California ISO recommends deleting requirement 1.1.2.1. This requirement is circular because one cannot know whether the known outage would result in Non-Consequential Load Loss when it occurs at the same time as a P1 event without performing the study in the first instance. Because this would effectively require one to study each P1 event combined with each known outage anyway, it would be simpler to delete 1.1.2.1 altogether while preserving 1.1.2.2 in order to directly address the relevant directive in FERC Order 786.

The California ISO recommends the following specific revisions based on the foregoing concerns:

1. Delete “, at a minimum:” from section 1.1.2 and replace with the full text of proposed 1.1.2.2 (“does not exclude known outage(s) solely based upon the outage duration.”).

2. Delete sections 1.1.2.1 and 1.1.2.2.

Second, the California ISO recommends deleting the proposed additional language in requirements 2.1.3 and 2.4.3. This new language would clarify that the P1 events to be studied are those that are “expected to produce more severe System impacts on [the responsible entity’s] portion of the BES.” However, this is already permitted under requirement 3.4. This new proposed language is unnecessary and should be deleted.

The California ISO recommends the following specific revisions based on the foregoing concerns:

1. Delete proposed additional language “expected to produce more severe System impacts on its portion of the BES,” from section 2.1.3.

2. Delete proposed additional language “expected to produce more severe System impacts on its portion of the BES,” from section 2.4.3.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC**

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|---|---|
| **Answer** | No |
| **Document Name** | |

| Comment | |
|---|---|
| SCE's key disagreement with the proposed revisions is the language of bullet D of Footnote 13. SCE provided comments on bullet D during draft 1 regarding a monitoring provision like that contained in bullets B & C. The drafting team provided feedback as to its decision at that time due to limitations of PRC-005 monitoring. For draft 2, SCE responded to the direct feedback with additional substantive information for consideration regarding the role PRC-005 monitoring that allows extended maintenance intervals because the equipment will indicate if there is an issue. However, the drafting team didn't provide a rationale for the continued rejection of SCE's proposal to exclude control circuitry through the trip coils that are monitored and reported. Respectfully, SCE wishes to reiterate the reliability value in monitoring control circuitry combined with higher periodicity testing requirements for components such as electromechanical lockout relays required by PRC-005. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| **Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4** | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| • The NERC Drafting Team should consider limiting single points of failure at Generation Facilities and develop a criteria for applicability to GOs (Example: Limit GO applicability to relays associated to interconnection points and not all relays that are part of PRC-005). It is understood that this Standard does not directly apply to the GO under the Applicability section of this Standard but it appears they could ultimately be required to create Corrective Action Plans (CAPs) by the Transmission Planner or Planning Coordinator for non-redundant components of a Protection System. Also, singular generation units are already accounted for in Planning Assessments so single points of failure at these locations should be exempt from this analysis. Additionally, the SDT should consider only requiring GOs to identify single points of failure to be included in Planning Assessments but not require GOs to develop Corrective Action Plans (CAPs). The proposed revisions as written, when applied to GOs, would provide little reliability benefit but could potentially result in significant cost associated with upgrading Facilities.<br><br>• Single protective relays and single control circuitry referenced in footnote 13 are prevalent for equipment at voltages 100kV -229kV and generally do not meet the redundancy requirements in the proposed revisions of this Standard. The SDT should consider making footnote 13 applicable to equipment at 230kV and above.<br><br>• Single communication systems referenced in footnote 13 should be clarified by the SDT and state backup communication can use time delay functionality (does not use communication system) if relays can clear normally. The current wording implies that two independent communication paths are required to report issue back to the Control Center. Additionally, the SDT should consider allowing weekly communication checkbacks that report back to the Control Center as a method to meet the communication requirements in footnote 13.<br><br>• A single dc supply referenced in footnote 13 would add significant cost with little benefit for dc supply open circuit monitoring in real-time. The SDT should consider addressing dc supply open circuit during quarterly battery maintenance in PRC-005-6 to reduce cost impact to industry. The estimated total cost for installing dc supply open circuit monitoring would be roughly $50,000 per location. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

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|---|---|
| **Oshani Pathirane - Oshani Pathirane On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

Hydro One still has concerns with the following points regarding Footnote 13:

1) 13c – The term "open circuit" is not clear. Please provide clarification of the term and an example of how it is typically monitored in the supplementary material for better understanding.

2) 13d – We recommend that a single trip coil that is "monitored and reported at a Control Center" be treated the same way that communication systems (Footnote 13b) and DC Supply (Footnote 13c) are treated (to meet the redundancy requirement).

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

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|---|---|
| **Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name** Tennessee Valley Authority | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

TVA supports JEA's comments. We believe a three-phase fault including protection system failure would have an extremely low probability of occurring. Requiring implementation of actions to prevent these extremely rare events would cause a large and unnecessary financial burden with little benefit to our system reliability.

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

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|---|---|
| **Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

See responses to Questions 1 and 2.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller, Group Name** MEAG Power

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

We disagree with the proposed revision to TPL-001-4. Particularly, the inclusion of the new planning event P8 is unwarranted and should be deleted along with the associated CAP and the implementation plan, and all the changes made to the performance requirements at the top of Table 1 (Performance Planning Events – Steady State & Stability) associated with the proposed P8 event, i.e., there is no change required in this section from the current TPL-001-4 standard (from Order No. 786). Similarly, no changes are required for requirement R4 sub-requirement 4.5 for extreme events and Cascading (keep this section unchanged from the current TPL-001-4 standard).

The replacement of the retired standards MOD-010 and MOD-012 with MOD-032 is appropriate.

The inclusion of measures (M) for each Requirement is appropriate.

The clarifications added for the planned maintenance outages of significant facilities from future planning assessments are appropriate and seem to adequately addresses the Commission's directive from Order No. 786 Paragraph 40.

The clarifications added for entity's spare equipment strategy for the unavailability of long lead time items are appropriate and seem to adequately addresses the Commission's directive from Order No. 786 Paragraph 89.

The replacement of the 'Special Protection Systems' with 'Remedial Action Schemes' is appropriate.

Clarifications added to the planning event P5 along with the new Footnote 13 are appropriate and seem to adequately address the concerns that the Commission raised with single points of failure in Protection System (for single phase faults) as well as the recommendations from the joint report from SPCS and SAMS.

The updated Footnote 13 adds clarity to the standard and addresses all the recommendations from the Joint Report from SPCS and SAMS for Footnote 13.

Suggestion: Restore the language from the last draft (Sept. 2017 version) under Table 1 – Extreme Events – stability bullets 2e through 2h (without the proposed 4.6 of draft 1 or the proposed 4.2.1 and 4.2.2 of draft 2) to address the recommendation from the Joint Report from SPCS and SAMS regarding the three phase faults together with single points of failure in protection system. This should adequately address the Commission's concern (for three phase faults) from Order No. 754 as well as the recommendations from the Joint Report from SPCS and SAMS.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name** Southern Company

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

While there are many improvements implemented in this posting, there are still some modifications that should be made as articulated in the responses to the previous questions in this Comment Form, and additionally:

Requriement 2, Part 1.5, we suggest modifying the following phrase (see BOLD font for modifying word): "…….the impact of this possible unavailability on System performance shall be assessed. The **analysis** shall be performed for the P0, P1, and P2 categories identified in Table 1….." to"…….the impact of this possible unavailability on System performance shall be assessed. The **assessment** shall be based on analysis performed for the P0, P1, and P2 categories identified in Table 1…..".

Part 2.1.3 and 2.4.3 - We propose alternative text for Part 2.1.3 and 2.4.3, "P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with the **selected** outages modeled in Requirement R1, Part 1.1.2, under those System peak, Off-Peak, **or other** conditions when **the selected** outages are scheduled **or planned to occur**."

The System peak or Off-Peak models will normally be suitable for the Part 2.1.3 requirement. However, explicitly requiring the assessment obligation to be based on only these models excludes the option of using of other models that can represent the applicable system conditions more appropriately than the System peak or Off-Peak models.

The addition of the word, "planned", allows the inclusion of outages identified by PCs or TPs that are necessary in the planning horizon to implement Corrective Actions Plans – as most if not all are likely not to be scheduled yet.

Item h in the first page of Table 1 should be relocated to "after Item e" but before the Steady State section. Then re-alphabetize accordingly.

Footnote 14 - We propose adding a **Footnote 14** that is noted in the Fault Type field of P5 and P8. The footnote would have wording like, "Transmission Planners (TPs) and Planning Coordinators (PCs) can perform the 3-phase fault simulations first for contingencies that are expected to produce more severe System impacts on its portion of the BES. Subsequent, corresponding SLG fault contingencies may be performed, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss or Cascading. "

Even with the relaxation of required performance, the rationale to include 3 phase faults with the failure a non redundant component of a Protection System is too onerous (P8).

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Rachel Coyne - Texas Reliability Entity, Inc. - 10** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

In addition to the issues noted in #2, Texas RE noticed the following:

- In Part 3.4, Texas RE is concerned that allowing registered entities to select which P1 events are “expected to produce more severe System impacts”, registered entities have the flexibility to ignore P1 events without determining the actual impact of the events. Texas RE recommends all P1 events should be selected.
- In Table 1, Texas RE noticed P8 is not listed in Steady State Only or Stability Only. Is it the SDT’s intent to leave it out of those conditions?

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

KCP&L recommends the Standard include language that will allow establishing the scope of contingencies in dynamics to a specific area local to the equipment.

**Concern**

The proposed revisions substantially expand required assessments and studies, including long-lead time equipment into dynamic analysis, and consideration of all outages—without limitation—during the assessment process.

The company recognizes the proposed revisions reflect the Orders’ language requiring consideration of outages without limitation, and so forth, but the language to satisfy the Orders require markedly greater resources.

**Recommendation**

KCP&L suggests adding language that provides an efficiency, or like efficiencies, in the assessment process and addresses the Standard Requirements. We suggest the following:

Requirement language or guidance that establishes the scope of contingencies in dynamics to a specific area local to the equipment. This provides an efficiency in the evaluation of contingencies by allowing the TP to draw a bus-ring around applicable equipment and evaluate contingencies within a smaller, yet relevant, range.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Michael Jones - National Grid USA - 1, Group Name** National Grid

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

| Comment | |
|---|---|
| National Grid would like to express our appreciation and supports the direction in which the TPL-001-5 SDT is proposing to adjust the NERC Reliability Standard TPL-001, including the creation of the proposed P8 event. We believe that, in particular, Footnote 13 still includes some ambiguity in defining what protection performance is needed to reduce the risk of reliability impact from Single Points of Failures, and would like to provide the following comments:<br><br>Does "spare equipment strategy" mean the existence of at least a single spare for major transmission equipment that has a lead time of more than one year; and does Requirement 2.4.5 imply that the existence of such a spare would eliminate the need to assess the impact of the possible unavailability of such equipment on System performance? If so, then Requirement 2.4.5 should be written this way.<br><br>As currently written, Requirement 2.4.5 lacks clarity. Every reasonable "spare equipment strategy" for equipment with a lead time of one year or more could result in the unavailability of such equipment; it is a matter of probability. For example, an Entity with 100 large power transformers could have a spare transformer strategy of maintaining one system spare. However, it is possible that two transformers could fail during time span of one year. With only one spare, the Entity would be exposed to operating the system for up to one year with one less transformer than designed. Even if the Entity has four (4) spares, it is still possible that five (5) transformers could fail during one year (albeit with much lower probability), which would leave the Entity similarly exposed. Greater clarity is required for Requirement 2.4.5, as is more criterion development.<br><br>It is not fully clear as to what constitutes "comparable" in the context of comparable Normal Clearing times in Table 1 Footnote 13 Part a. Please also clarify what constitutes an "alternative" relay, beyond allowing for response to non-electrical quantities. What if alternative relay does not provide the same clearing time as the primary relay (e.g., the alternate relay is an impedance relay with longer Zone 2 timer, or the alternative relay is an overcurrent relay, while the primary relay is an impedance relay). Could any relay classified as an "alternative" relay be considered as 'redundant', and therefore Footnote 13 would not apply? We would like the SDT to provide guidance on what constitutes "comparable" Normal Clearing times and an "alternative" relay, e.g., in a 'Guidelines and Technical Basis' section.<br><br>Even after including auxiliary relays and lockout relays, it is still not fully clear what the term "control circuitry" includes. As written, it seems that "control circuitry" (apart from wiring) includes auxiliary relays and lockout relays. Since we believe it could be advantageous to provide a more 'formal' definition of this term, we suggest providing additional guidance in a 'Guidelines and Technical Basis' section and/or including a definition for "control circuitry" in the 'Glossary of Terms Used in NERC Reliability Standards'.<br><br>As another Entity brought up during the NERC webinar on March 22, 2018, why does the exclusion (provided per Footnote 13 Part b) for communication systems not also extend to single protective relays (referred to in Footnote 13 item a), if monitored or reported at a Control Center?<br><br>We also believe it would be of value to consider requesting entities to document the rationale regarding considerations regarding non-redundant components of a Protection System evaluated per Footnote 13. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Robert Ganley - Long Island Power Authority - 1** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

It is recommended to consider revising Sections 3.2 and 3.5 in a similar manner to the proposed revisions to Sections 4.2 and 4.5.

*Additional Comment for consideration, related to Requirement #4 (related to clarification of the Standard):*

Requirement 4.1 states that "Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1….." Immediately after 4.1, sub-requirements 4.1.1 through 4.1.3 specify specific system/generator stability performance requirements which are not mentioned in Table 1. Our observation is that Table 1 includes steady state and stability related performance requirements. This apparent placement of performance requirements in more than one location within the Standard document is confusing. Recommendation for consideration is to move sub-requirements 4.1.1 through 4.1.3 to Table 1.

*Additional Comment for consideration, related to clarification of the Standard:*

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).

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|---|---|
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6; - Michael Brytowski** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

GRE agrees with the MRO NSRF and ACES comments and:

**13b. Single communications system**

- Monitoring a single communication scheme does not provide the same robustness as having a redundant communication scheme.
- Communication failures in blocking schemes do not result in delayed clearing.
- 
- It is important for planning to identify locations where delayed clearing of faults (such as in zone 2 time) could lead to cascading outages or stability concerns. If faster clearing times are required, these elements should have redundant communications installed. In many companies, these studies are already being performed. If not, the requirement to study the impact of failures of single communication schemes could drive a company to identify where redundant communications are required.
- 

- The intent of the standard is to study failures/contingencies which are most impactful to the BES. Typically, single communication schemes are in place to limit damage, improve coordination and as a good design practice. If a communication scheme is installed for these reasons, the "Normal clearing time" of the protective system may not be necessary to maintain system stability or prevent cascading outages.
-
- The use of the phrase "Normal Clearing time" should be changed to "time required to maintain system stability" or "critical clearing time" or "time to prevent misoperation, cascading, or unintentional islanding". Otherwise, non-redundant communications systems which were not installed for the purpose of maintaining stability would need to be evaluated (or monitored). Such evaluation would be an unnecessary burden.

**13c. Single station dc supply**

- How common is the monitoring of a battery open circuit condition? FERC Order 754 report says it was not common at the time of the order to have redundant batteries, and it is probably not that common now to have redundant batteries or open circuit monitoring. Without open circuit monitoring, it is possible that a charger might mask an open circuit in the battery. Open circuit monitoring is possible but is not universally applied where there are single batteries.

- FERC Order 754 only applied to 200 kV substations or higher. The number of substations lower than 200 kV without redundant batteries will be substantially higher.

- GRE's standard design for new 230 kV substations or higher is to install redundant batteries, but we have many existing facilities that have one battery bank with redundant AC supply. Monitoring for open DC supply has not been considered in the past when defining a redundant DC supply.

- Periodic open circuit testing as required by PRC-005 will likely not meet the requirement of open circuit monitoring.

- This requirement seems likely to drive industry to either retrofit existing installations with open circuit monitoring or to install redundant DC supplies. Is this the appropriate place to drive that decision, for a high impact/low risk battery failure? This could be a significant impact, and it appears that this impact may not be fully understood in the context of reviewing this standard.

- Should a risk based approach be considered—an open circuit battery failure is a low risk, high impact event?

**13d. Single control circuitry**

- As written, this seems to apply to components (coils, auxiliary relays) and wires.

- Verifying where there is single control circuitry could be costly—there are many legacy installations which may not follow present design practices and would require some type of manual review of substation drawings.

- Consider audit evidence for this requirement. Documentation of present design standards which meet the requirement is practical, will it be sufficient?

- A risk based approach to this requirement which limits the review to redundancy of components instead of wires may be practical. The failure rate of wiring is far less than that of components.

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| Likes 0 | |
| Dislikes 0 | |

| **Response** |
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| **Neil Swearingen - Salt River Project - 1,3,5,6 - WECC** | |
|---|---|
| **Answer** | No |

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|---|---|
| **Document Name** | |
| **Comment** | |
| SRP agrees with the reliability goals of TPL-001-5, but also has some recommendations. SRP recommends moving the final sentence of 3.5. to the end of 3.2., just as was done between 4.5. and 4.2. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| See comments from MRO NSRF. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Leonard Kula - Independent Electricity System Operator - 2** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| Please see Comment #1 and Comment #2 | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name** PPL NERC Registered Affiliates | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

Footnote 13, item c lacks clarity as to what constitutes a single station d.c. supply. Typical stations are configured with two components that operate as a single d.c. supply system – an inverter and battery bank. Each of these components provide some redundancy to provide d.c. load for failure of the other component, which could be interpreted as meeting the requirements for a redundant system with no further monitoring required per Proposed Reliability Standard TPL-001-5 Table 1. However, if the entire d.c. supply system is considered a single component, then the requirement to monitor for open circuit is not sufficiently clear to determine if the inverter, battery, or load must be monitored for open circuit. PPL NERC Registered Affiliates requests clarification to Proposed Reliability Standard TPL-001-5 Footnote 13, item c – specifically, as to what constitutes a single station d.c. supply to eliminate ambiguity of the requirement to monitor for open circuit needs.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6**

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| **Answer** | No |
| **Document Name** | |

**Comment**

**Part 2.1.3** - We suggest adjustments to Part 2.1.3 that coordinate with our Question 2 comments, “P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned.”

We propose that the standard include wording that will allow the option of studying any known outages under the conditions that they are planned to occur when those conditions are more appropriate than System peak or Off-Peak conditions.

**Part 2.4.3** - We propose adjustments to Part 2.4.3 that coordinate with our Question 2 comments, “P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned”.

Same explanatory text as Part 2.1.3.

**Table 13, Footnote 13**

For 13.b, the monitoring and reporting exception is not consistent with the 13.a requirements for protective relay redundancy, even though communication system components can be very similar in design and performance. The interval of monitoring and reporting is not defined. The ability to monitor the status of a communication system component does not fully mitigate the risk of the failure of a non-redundant component and should be treated like protection components identified in 13.a.

For 13.c, Wording should be added to clearly state that the combination of a dc charger and a dc battery is part of a single dc supply to avoid inconsistent interpretation of a single dc supply. The interval of monitoring and reporting is not defined. The PRC-005 standard requires that “Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.” Some battery open circuit monitors, that are presently available, have monitor intervals that only occur every few months, which are significantly longer than the PRC-005 maintenance requirement. The normally long open circuit monitoring intervals is expected to make the open circuit monitoring exception irrelevant.

| | |
|---|---|
| For 13.d, the wording of “single control circuitry” is non-specific and may lead to inconsistent interpretation. The SDT should use a risk-based approach for identifying applicable circuitry that recognizes that wiring has a much lower risk of failure than the other Footnote 13 components. A risk-based approach would allow the industry to appropriately prioritize resources to meet the objectives of the standard and insure Bulk Electric System reliability.<br><br>**Footnote 14** - We propose adding a Footnote 14 that is noted in the Fault Type field of P5 and P8. The footnote would have wording like, “Transmission Planners (TPs) and Planning Coordinators (PCs) can perform the 3-phase fault simulations first for contingencies that are expected to produce more severe System impacts on its portion of the BES, than the corresponding SLG fault contingency. Subsequent, corresponding SLG fault contingencies may be performed, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. “ | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name** FMPA | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| In addition to the comments written above in answer to Questions 1 and 2, FMPA notes that the questions in this comment form do not cover all of the changes. Order 786 required more than just the changes to Requirement 1, part 1.1.2. There is also the addition of Requirement 2.4.5, adding stability analysis as required per an entity’s Spare Equipment Strategy. FMPA notes that while studying these events in steady state using P0, P1 and P2 events, doing so for stability doesn’t quite make sense. FMPA would support an alternative that simply stipulates that the PA/TP should study which ever Planning event it feels would be the most prudent based on the specific facility(ies) that could be out of service. Many entities do not run P1 events in stability – rather, they simulate other Planning events that, in their engineering judgment, produce more severe system impacts. Thus it doesn’t make sense to add P1 events just because a major facility could be out of service – this may not change the fact that another event such as a P4 or P5 may still be more important to study due to clearing times, and it doesn’t really save the entity any time. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **John Bee - Exelon - 3** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

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| See Exelon TO Utilities Comments |

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| Likes 0 | |
| Dislikes 0 | |

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| **Response** |
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| **Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF** |

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|---|---|
| **Answer** | No |
| **Document Name** | |

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| **Comment** |
| See response to questions 1 and 2. |

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| Likes 0 | |
| Dislikes 0 | |

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| **Response** |
| |
| **Douglas Johnson - American Transmission Company, LLC - 1** |

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|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

**Part 2.1.3** - We suggest adjustments to Part 2.1.3 that coordinate with our Question 2 comments, "P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned.

We propose that the standard include wording that will allow the option of studying any known outages under the conditions that they are planned to occur when those conditions are more appropriate than System peak or Off-Peak conditions.

**Part 2.4.3** - We propose adjustments to Part 2.4.3 that coordinate with our Question 2 comments, "P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned.

Same explanatory text as Part 2.1.3.

**Table 1, Footnote 13**

For 13.b, the monitoring and reporting exception is not consistent with the 13.a requirements for protective relay redundancy, even though communication system components can be very similar in design and performance. The interval of monitoring and reporting is not defined. The ability to monitor the status of a communication system component does not fully mitigate the risk of the failure of a non-redundant component and should be treated like protection components identified in 13.a.

For 13.c, Wording should be added to clearly state that the combination of a dc charger and a dc battery is part of a single dc supply to avoid inconsistent interpretation of a single dc supply. The interval of monitoring and reporting is not defined. The PRC-005 standard requires checking dc batteries for the open circuit condition at least every 18 months. Some battery open circuit monitors, that are presently available, have monitor intervals that only occur every few months, which are significantly shorter than the PRC-005 maintenance requirement. The PRC-005 standard also requires the checking of dc battery voltage levels every 4 months. Finally, the PRC-005 standard requires that “Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.” Does the SDT think these timeframes are acceptable?

For 13.d, the wording of “single control circuitry” is non-specific and may lead to inconsistent interpretation. The SDT should use a risk-based approach for identifying applicable circuitry that recognizes that wiring has a much lower risk of failure than the other Footnote 13 components. A risk-based approach would allow the industry to appropriately prioritize resources to meet the objectives of the standard and insure Bulk Electric System reliability.

**Footnote 14 -** We propose adding a Footnote 14 that is noted in the Fault Type field of P5 and P8. The footnote would have wording like, “Transmission Planners (TPs) and Planning Coordinators (PCs) can perform the 3-phase fault simulations first for contingencies that are expected to produce more severe System impacts on its portion of the BES (P8), than the corresponding SLG fault contingency (P5). And only simulate a SLG fault of the corresponding contingency, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. “

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Mike Smith - Manitoba Hydro - 1, Group Name** Manitoba Hydro

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

Manitoba Hydro suggests that R1.1.2.2 be revised as suggested above. The P8 event should be moved to extreme events. The other changes are acceptable.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Ellen Oswald - Midcontinent ISO, Inc. - 2**

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|---|---|
| **Answer** | No |
| **Document Name** | |

| Comment | |
|---|---|

**Part 2.1.3 -** We suggest adjustments to Part 2.1.3 that coordinate with our Question 2 comments, “P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned.”

We propose that the standard include wording that will allow the option of studying any known outages under the conditions that they are planned to occur when those conditions are more appropriate than System peak or Off-Peak conditions.

**Part 2.4.3 -** We propose adjustments to Part 2.4.3 that coordinate with our Question 2 comments, “P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned”.

Same explanatory text as Part 2.1.3.

**Table 13, Footnote 13**

For 13.b, the monitoring and reporting exception is not consistent with the 13.a requirements for protective relay redundancy, even though communication system components can be very similar in design and performance. The interval of monitoring and reporting is not defined.

For 13.c, Wording should be added to clearly state that the combination of a dc charger and a dc battery is part of a single dc supply to avoid inconsistent interpretation of a single dc supply.  The interval of monitoring and reporting is not defined. The PRC-005 standard requires that “Alarms are reported within 24 hours of detection to a location where corrective action can be initiated.” Some battery open circuit monitors, that are presently available, have monitor intervals that only occur every few months, which are significantly longer than the PRC-005 maintenance requirement.

For 13.d, the wording of “single control circuitry” is non-specific and may lead to inconsistent interpretation.  The SDT should use a risk-based approach for identifying applicable circuitry that recognizes that wiring has a much lower risk of failure than the other Footnote 13 components. A risk-based approach would allow the industry to appropriately prioritize resources to meet the objectives of the standard and insure Bulk Electric System reliability.

**Footnote 14 -** We propose adding a Footnote 14 that is noted in the Fault Type field of P5 and P8. The footnote would have wording like, “Transmission Planners (TPs) and Planning Coordinators (PCs) can perform the 3-phase fault simulations first for contingencies that are expected to produce more severe System impacts on its portion of the BES, than the corresponding SLG fault contingency. Subsequent, corresponding SLG fault contingencies may be performed, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. “

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

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| MEC supports NSRF comments. |

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| Likes 0 | |
| Dislikes 0 | |

| **Response** |
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| **Dennis Sismaet - Northern California Power Agency - 6** | |
|---|---|
| **Answer** | No |
| **Document Name** | |

| **Comment** |
|---|
| Please see JEA's comments. |

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

| **Response** |
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| **Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins** | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

NVE proposes the following changes for various requirements listed below:

**Table 1, Footnote 13d**

NVE recognizes the importance of studying the impact of a failure of a single control circuitry, but has concerns with the duplication of component types in this footnote with other planning events. Studying the failure of control circuitry associated with a breaker trip coil would result in a breaker failing to operate for a fault. This is the same effect as a fault plus a stuck breaker. NVE recommends that Footnote 13d be modified to include studying the failure of auxiliary relays and lockout relays. Footnote 10 should be modified to include scenarios of a failure of a single breaker trip coil to operate.

**Table 1, Footnote 13c**

Wording to this footnote should be changed to match the portion of the definition of Protection System associated with dc supply to ensure that the failure of any component of a dc supply is studied.

*A single station dc supply associated with protective functions (including station batteries, battery chargers, and non-battery based dc supply) required for Normal Clearing….*

**R4.2 and R4.5**

NVE agrees with the proposed changes to R4.2 and R4.5.  Given that the wording and intent of R3.2 and R3.5 is the same as R4.2 anD R4.5, but for different portions of the planning study (steady state vs dynamic), NVE recommends that R3.2 and R3.5 be modified to match R4.2 ans R4.5 to maintain consistency.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6**

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|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

LADWP doesn not agrtee with the new proposed revisions specifically the new planning event P8 and the changes made to R4.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name** OKGE

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|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

OG&E recommends that Table 1, Footnote 13(d) should be revised to allow exceptions for trip coil circuit monitoring as follows:

“d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing**, which is not monitored or not reported at a Control Center**.

OG&E suggests restoring the language contained in the last draft (Sept. 2017 version) under Table 1 – Extreme Events – stability bullets 2e through 2h (but without the proposed 4.6 of draft 1 or the proposed 4.2.1 and 4.2.2 of draft 2) to address the Commission’s directive from Order No. 754, and is consistent with the recommendations from the Joint Report regarding three phase faults.

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| Likes 0 | |

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| Dislikes 0 | |
| **Response** | |
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| **Quintin Lee - Eversource Energy - 1, Group Name** Eversource Group | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| See Question 2 response | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Marty Hostler - Northern California Power Agency - 5** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| See JEAs response. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| See above comments in Questions 1 & 2. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

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|---|---|
| **Russel Mountjoy - Midwest Reliability Organization - 10, Group Name** MRO NSRF | |
| **Answer** | No |
| **Document Name** | |

**Comment**

**Part 2.1.3** - We suggest adjustments to Part 2.1.3 that coordinate with our Question 2 comments, "P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned."

We propose that the standard include wording that will allow the option of studying any known outages under the conditions that they are planned to occur when those conditions are more appropriate than System peak or Off-Peak conditions.

**Part 2.4.3** - We propose adjustments to Part 2.4.3 that coordinate with our Question 2 comments, "P1 events in Table 1 expected to produce more severe System impacts on its portion of the BES, with known outages modeled as in Requirement R1, Part 1.1.2, under System peak or Off-Peak or other conditions when known outages are planned".

Same explanatory text as Part 2.1.3.

**Table 13, Footnote 13**

For 13.b, the monitoring and reporting exception is not consistent with the 13.a requirements for protective relay redundancy, even though communication system components can be very similar in design and performance. The interval of monitoring and reporting is not defined.

For 13.c, Wording should be added to clearly state that the combination of a dc charger and a dc battery is part of a single dc supply to avoid inconsistent interpretation of a single dc supply. The interval of monitoring and reporting is not defined. The PRC-005 standard requires that "Alarms are reported within 24 hours of detection to a location where corrective action can be initiated." Some battery open circuit monitors, that are presently available, have monitor intervals that only occur every few months, which are significantly longer than the PRC-005 maintenance requirement.

For 13.d, the wording of "single control circuitry" is non-specific and may lead to inconsistent interpretation. The SDT should use a risk-based approach for identifying applicable circuitry that recognizes that wiring has a much lower risk of failure than the other Footnote 13 components. A risk-based approach would allow the industry to appropriately prioritize resources to meet the objectives of the standard and insure Bulk Electric System reliability.

**Footnote 14** - We propose adding a Footnote 14 that is noted in the Fault Type field of P5 and P8. The footnote would have wording like, "Transmission Planners (TPs) and Planning Coordinators contingency. Subsequent, corresponding SLG fault contingencies may be performed, if the BES level is EHV and the 3-phase simulation resulted in the interruption of Firm Transmission Service or Non-Consequential Load Loss. "

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| Likes 0 | |
| Dislikes 0 | |

**Response**

| | |
|---|---|
| **Shawn Abrams - Santee Cooper - 1** | |
| **Answer** | No |

| | |
|---|---|
| **Document Name** | |
| **Comment** | |

Santee Cooper disagrees with the proposed revisions to TPL-001-4. The inclusion of a new planning event that requires a CAP goes against Section 215 of the Federal Power Act which expressly prohibits NERC from promulgating standards which would require utilities to enlarge facilities or construct new transmission or generation.

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

**Patricia Robertson - BC Hydro and Power Authority - 1,3,5, Group Name** BC Hydro

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

***BC Hydro appreciates the efforts of the SDT in revising TPL-001-5 – Transmission System Planning Performance Requirements. BC Hydro votes "No" and wishes to provide the following comment.***

***The proposed amendments scope from Single Point of Failure is very wide, which will apply to the entire bulk electric system i.e. 100 kV and above. Our ballot would have been affirmative if the scope were limited to extra high voltage (360 kV and above), where a single point of protection failure after a fault can trigger a major system disturbance.***

***Below extra high voltage levels, BC Hydro protection systems are built using principles of good utility protection practices, as described in the ANSI/IEEE standards and guides, to ensure that they have acceptable reliability i.e. clear faults without mis-operating. Our protection systems are largely redundant but still can have a single point of failure, such as where there is a shared breaker trip coil or a single telecom fibre etc. Based on our fifty years of operating experience, there is no known case where a single point of failure in our high voltage protection system precipitated in a major system disturbance event. It is because probability of a single failure (in our redundant high voltage protection system) impacting our system performance is negligible. Yet demonstrating compliance to the proposed amendments will require BC Hydro to redirect our critical resources (financial and people) in identifying single points of failure in our every single high voltage P&C asset, estimate incremental protection clearing time associated with that failure, and then demonstrate acceptable system performance during the event. Instead of redirecting our critical resources to demonstrate compliance to this negligible probability event, BC Hydro will receive higher reliability benefits by continuing to invest our resources in upgrading the aging protection systems.***

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|---|---|
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

**Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name** Lincoln Electric System

| | |
|---|---|
| **Answer** | No |

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|---|---|
| **Document Name** | |
| **Comment** | |

Although appreciative of the drafting team's work on TPL-001-5, LES believes the following changes would provide greater clarity within the standard.

R2.1.3 & R2.4.3 – Recommend "when known outages are scheduled" be changed to "when known outages **occur**" to provide greater clarity.

R2.4.3 – The objective for including known outages in TPL-001-5 should be to ensure that all types of known outages are being reviewed while keeping the burden of additional stability analyses within reason. As currently drafted, the standard would require both steady state and stability analyses for all known outages included in the Planning Assessment. LES recommends modifying the standard to allow steady state analyses and limit stability analyses based on the use of Engineering Judgement in the Transmission Planner's technical rationale for selecting known outages. Recommend changing R2.4.3 to state "…under those System peak or Off-Peak conditions when known outages occur **and have been identified as requiring Stability analysis**".

Footnote 13a: To ensure "comparable" isn't mistaken to mean having identical Clearing times, LES suggests revising footnote 13a to instead state "…that provides comparable**, but not necessarily identical,** Normal Clearing times".

Footnote 13c: LES recommends removing "open circuit" from Footnote 13c. The absence of open circuit monitoring is too restrictive to consider a single station DC supply as non-redundant. Both a battery charger and battery provide DC supply redundancy because either device can provide DC power if the other device fails or has an open circuit. Additionally, PRC-005 provides adequate testing for open circuits.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Thomas Foltz - AEP - 5** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

In the response to Question 1, we voiced our concerns on the inclusion of P8. Rather than its inclusion, one possible alternative would be to redefine the definition of Delayed Fault Clearing to only include backup protection system with an intentional time delay.  A separate term could be created for Breaker Failure Fault Clearing.  Note that in the NERC technical paper "Protection System Reliability Redundancy of Protection System Elements" by the NERC System Protection and Control Subcommittee dated January 2009, page 13, the committee had to clarify the term for the purpose of their paper. Currently, this white paper is the primary source of guidance for this very complex topic. Due to the expansion of non-redundant components included in the proposed draft of the Standard, the terms provided in the NERC Glossary need to be further developed in order to provide clarity for their new application to this standard.

As stated in previous comment periods, we believe usage of the word "comparable" within footnote 13a is ambiguous. While we are not completely certain, we suspect the SDT means "less than or equal to" when using this word. If so, it would be preferable to instead state "A single protective relay which responds to electrical quantities, without an alternative (which may or may not respond to electrical quantities) that provides a clearing time less than or equal to Normal Clearing times;"

In both 13b and 13c, using the word "or" within "is not monitored or not reported at a Control Center" may not be consistently interpreted. Any possible confusion might be eliminated by instead using either "not monitored at a Control Center" or "is not monitored *and* not reported at a Control Center" in both 13b and 13c.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Fred Frederick - Southern Indiana Gas and Electric Co. - 3**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

We feel that more explanation/guidance is needed to address what is and isn't included in the "components of a Protection System."  The research to determine which of these components is a single point of failure, and what the delayed clearing time would be, is potentially quite expansive.  We would like to have a more clear idea of the scope of this work and how the impacts differ from P4 and the existing P5 contingencies.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

**Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name** Chelan PUD

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|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

CHPD disagrees with the proposed revision to TPL-001-4. Particularly, the inclusion of the new Planning Event P8 is unwarranted and should be deleted along with the associated CAP and the implementation plan, and all the changes made to the performance requirements at the top of Table 1 (Performance Planning Events – Steady State & Stability) associated with the proposed P8 event, i.e., there is no change required in this section from the current TPL-001-4 standard (from Order No. 786). Similarly, no changes are required for requirement R4 sub-requirement 4.5 for Extreme Events and Cascading (keep this section unchanged from the current TPL-001-4 standard).

In moving the three-phase fault with protection system failure from an Extreme Event to a P8 Planning Event, the SDT has also changed the required performance levels from that of the Extreme Event to those of the planning standard, which creates an undue burden.  Also, while the SDT stated in their Consideration of Comments to TPL-001-5 Draft 2 Question 1 “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,” the current language of the proposed standard doesn’t clearly state that a CAP isn’t required.  CHPD disagrees with these changes.

The replacement of the retired standards MOD-010 and MOD-012 with MOD-032 is appropriate.

Clarifications added to the planning event P5 along with the new Footnote 13 are appropriate and seem to adequately address the concerns that the Commission raised with single points of failure in Protection System (for single phase faults) as well as the recommendations from the Joint Report from SPCS and SAMS.

The updated Footnote 13 adds clarity to the standard and addresses all the recommendations from the Joint Report from SPCS and SAMS for Footnote 13.  However, CHPD would like to see non-redundant but monitored relays and control circuitry (as defined in Table 1 Footnote 13.a. and 13.d.) have the same exclusion as the monitored communication systems and station dc supplies as allowed in Table 1 Footnote 13.b. and 13.c. for Planning Events P5 and P8.

CHPD suggests the SDT restore the language from the last draft (Sept. 2017 version) under Table 1 – Extreme Events – stability bullets 2e through 2h (without the proposed 4.6 of draft 1 or the proposed 4.2.1 and 4.2.2 of draft 2) to address the recommendation from the Joint Report from SPCS and SAMS regarding the three phase faults together with single points of failure in protection system. This adequately addresses FERC's concern regarding three phase faults from Order No. 754 as well as the recommendations from the Joint Report from SPCS and SAMS.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Jeff Landis - Platte River Power Authority - 3**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

PRPA supports JEA comments.

JEA disagrees with the proposed revision to TPL-001-4. Particularly, the inclusion of the new planning event P8 is unwarranted and should be deleted along with the associated CAP and the implementation plan, and all the changes made to the performance requirements at the top of Table 1 (Performance Planning Events – Steady State & Stability) associated with the proposed P8 event, i.e., there is no change required in this section from the current TPL-001-4 standard (from Order No. 786). Similarly, no changes are required for requirement R4 subrequirement 4.5 for extreme events and Cascading (keep this section unchanged from the current TPL-001-4 standard).

The replacement of the retired standards MOD-010 and MOD-012 with MOD-032 is appropriate.

The inclusion of measures (M) for each Requirement is appropriate.

The clarifications added for the planned maintenance outages of significant facilities from future planning assessments are appropriate and seem to adequately addresses the Commission's directive from Order No. 786 Paragraph 40.

The clarifications added for entity's spare equipment strategy for the unavailability of long lead time items are appropriate and seem to adequately addresses the Commission's directive from Order No. 786 Paragraph 89.

The replacement of the 'Special Protection Systems' with 'Remedial Action Schemes' is appropriate.

Clarifications added to the planning event P5 along with the new Footnote 13 are appropriate and seem to adequately address the concerns that the Commission raised with single points of failure

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in Protection System (for single phase faults) as well as the recommendations from the joint report from SPCS and SAMS.

The updated Footnote 13 adds clarity to the standard and addresses all the recommendations from the Joint Report from SPCS and SAMS for Footnote 13.

Suggestion: Restore the language from the last draft (Sept. 2017 version) under Table 1 – Extreme Events – stability bullets 2e through 2h (without the proposed 4.6 of draft 1 or the proposed 4.2.1 and 4.2.2 of draft 2) to address the recommendation from the Joint Report from SPCS and SAMS regarding the three phase faults together with single points of failure in protection system. This should adequately address the Commission's concern (for three phase faults) from Order No. 754 as well as the recommendations from the Joint Report from SPCS and SAMS.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

Tri-State does not agree with the language of Footnote 13:

Footnote 13 is weakly worded and suggests that elements of a protection system should be consider rather than shall be studied. Stronger language which clearly defines what components of a protection that are included and what are excluded should be used.

Section D: The standard does not adequately explain the difference between a breaker failing to operating and failure of an element of a protection system resulting in the breaker failing to operate. In most cases, the protection events and post-contingency system states are identical. An addendum or reference to technical documentation which clearly explains the scenarios where they may differ should be included.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Kelsi Rigby - APS - Arizona Public Service Co. - 5**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

As stated in response to Question 2 above, AZPS recommends that a definitive time period of "more than 3 months" be added to Requirement 1, Part 1.1.2. Please refer to AZPS's comments in response to Question 2.

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| Likes 0 | |
| Dislikes 0 | |

**Response**

| Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| With the exception of clarification for R1.1.2.2 and the P5/P8 suggested change, BPA is in agreement with the other revisions. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| John Seelke - LS Power Transmission, LLC - 1 | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| See thw response to Q2. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 6 | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| We agree with the conforming revisions specifics but we do not agree with additional modifications. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| **Joe McClung - JEA - 3,5 - FRCC, Group Name** JEA Voters | |
|---|---|
| **Answer** | No |

| | |
|---|---|
| **Document Name** | |

**Comment**

JEA disagrees with the proposed revision to TPL-001-4. Particularly, the inclusion of the new planning event P8 is unwarranted and should be deleted along with the associated CAP and the implementation plan, and all the changes made to the performance requirements at the top of Table 1 (Performance Planning Events – Steady State & Stability) associated with the proposed P8 event, i.e., there is no change required in this section from the current TPL-001-4 standard (from Order No. 786). Similarly, no changes are required for requirement R4 sub-requirement 4.5 for extreme events and Cascading (keep this section unchanged from the current TPL-001-4 standard).

The replacement of the retired standards MOD-010 and MOD-012 with MOD-032 is appropriate.

The inclusion of measures (M) for each Requirement is appropriate.

The clarifications added for the planned maintenance outages of significant facilities from future planning assessments are appropriate and seem to adequately addresses the Commission's directive from Order No. 786 Paragraph 40.

The clarifications added for entity's spare equipment strategy for the unavailability of long lead time items are appropriate and seem to adequately addresses the Commission's directive from Order No. 786 Paragraph 89.

The replacement of the 'Special Protection Systems' with 'Remedial Action Schemes' is appropriate.

Clarifications added to the planning event P5 along with the new Footnote 13 are appropriate and seem to adequately address the concerns that the Commission raised with single points of failure in Protection System (for single phase faults) as well as the recommendations from the joint report from SPCS and SAMS.

The updated Footnote 13 adds clarity to the standard and addresses all the recommendations from the Joint Report from SPCS and SAMS for Footnote 13.

**Suggestion**: Restore the language from the last draft (Sept. 2017 version) under Table 1 – Extreme Events – stability bullets 2e through 2h (without the proposed 4.6 of draft 1 or the proposed 4.2.1 and 4.2.2 of draft 2) to address the recommendation from the Joint Report from SPCS and SAMS regarding the three phase faults together with single points of failure in protection system. This should adequately address the Commission's concern (for three phase faults) from Order No. 754 as well as the recommendations from the Joint Report from SPCS and SAMS.

| | |
|---|---|
| Likes 1 | JEA, 5, Babik John |
| Dislikes 0 | |

**Response**

**Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

The proposed change to requirement R1, part 1.1.2 to eliminate the six month minimum duration requirement for considering known outages introduces duplication of the studies currently performed in TOP-003 and IRO-017 Operational Planning Assessments. Removing the six month threshold also adds a considerable burden on the annual Planning Assessment without providing significant value by requiring studies be performed for short term maintenance outages in the Planning Horizon.

| | |
|---|---|
| The annual TPL-001-4 Planning Assessments represent projected system conditions in the near-term and long-term planning horizons and are not meant to identify operational concerns for outages shorter than six months. The system models used in the Planning Assessment represent a general snapshot of stressed system conditions with all facilities in-service. Daily operational conditions almost never have the system entirely intact and available due to necessary system maintenance and testing. In addition, the information regarding planned outages occurring beyond year one of the near-term planning horizon would be expected to be limited or unavailable as most outages are scheduled within two months of the requested outage time. For these reasons, outages shorter than six months are more accurately addressed in the operations planning horizon, when more information is available regarding overlapping outages and current system conditions.<br><br>Planned outages are considered in Operational Planning Assessments. T**he IRO-017 standard establishes the outage coordination process** within the operations planning horizon, which covers the period from day-ahead to one year out. The outage coordination process includes development and communication of outage schedules, evaluating impacts and developing operating plans to mitigate outage conflicts, or rescheduling outages when necessary in order to reduce the reliability impact of the critical outage. This process ensures a more accurate modeling of expected system conditions, including information on concurrent outages. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Seattle City Light - 5 - WECC** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Bridget Silvia - Sempra - San Diego Gas and Electric - 3** | |

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| **Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin** | |
|---|---|
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |

**Table 1, Footnote 13** – The ability to monitor the status of a Protection System Component does not fully mitigate the risk of the failure of a non-redundant component. The exception of 13b is not consistent with the requirements for redundancy in protective relays, even though the components can be very similar in design and performance.

For 13.b, consider removing the qualification, "which is not monitored or reported within 24 hours at a Control Center". If the SDT believes the qualifications for monitoring and reporting are valid for the communication channel for a communications based relay scheme and elects to leave this, then ITC would only then suggest to add the same "which is not monitored or reported within 24 hours at a Control Center" qualification to 13.a . ITC, however, believes the better wording for the standard is to not have this gualification in either 13.a or 13.b.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| **Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1** | |
|---|---|
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |

We do however propose the following improvements :

- Requirement 2.5 addresses "material generation additions or changes". These additions or changes should already have been included in the model as per (renumbered) R1.1.3. Thus 2.5 is superfluous. However if SDT retains this requirement, it should also address other material additions or changes such as load increase or relocation.
- Requirement 2.7.1: Examples should not be in a requirement, they should be moved to guidance.

- Replace « assessment » in requirements 3.3.1.1 and 4.3.1.2 with « Planning Assessment »

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| Requirement 2.4.3 has been added to TPL-004-4, which caused the Requirement previously identified as 2.4.3 to be renumbered to 2.4.4. Therefore, in the second to last sentence where a reference is made to Requirement 2.4.3, the reference needs to be changed to 2.4.4. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Hasan Matin - Orlando Utilities Commission - 2 - FRCC** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| While OUC agrees with the addition of P8, OUC believes clarity needs to be added to Requirement 1 in order to avoid the TPL-001-5 standard overlapping with Operations Planning, and believes an outage duration would be an appropriate way to filter outages of less significance that Operations Planning would otherwise be assessing day-to-day. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **David Jendras - Ameren - Ameren Services - 3** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |

| | |
|---|---|
| We generally agree with the changes, except for R1.1.2.1 as noted above. Also, Is there a need to consider a three-phase fault on a shunt device with a stuck breaker resulting in Delayed Fault Clearing? (See Table 1 Stability Extreme Events) It appears this item is missing. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| The following questions/requests were previously submitted; however, Tacoma Power is not clear about the drafting team's responses.<br><br>1. 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.<br><br>2. Additional clarification is requested on the demarcation between station DC supply and control circuitry for purposes of TPL-001-5. It is recommended that the main breaker of DC panels be considered part of the station DC supply. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| We can agree with the changes, notwithstanding our response regarding Requirement 1, Part 1.1.2. The standard drafting team should revisit Requirement 1, Part 1.1.2.1. if the ballot does not pass. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

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|---|---|
| **Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name** RSC no Hydro One, NYISO and Eversource | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Jeffrey DePriest - DTE Energy - Detroit Edison Company - 3,4,5, Group Name** DTE Electric | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Chris Scanlon - Exelon - 1, Group Name** Exelon Utilities | |
| **Answer** | |
| **Document Name** | |
| **Comment** | |

It is recommended that for P5 and P8 events in Table 1, the Drafting Team consider modifying the phrase “Fault plus non-redundant component of a Protection System failure to operate” to “Fault plus single component of a Protection System failure to operate” and modifying the phrase “Delayed Fault Clearing due to the failure of a non-redundant relay component of a Protection System protecting the Faulted element to operate as designed” to “Delayed Fault Clearing due to the failure of a single component of a Protection System protecting the Faulted element to operate as designed”. Similarly, note 13 in Table 1 might be modified to read “For purposes of this standard, failure of a single component of a Protection System is considered to be as follows”. It is suggested that this language might describe the same event a bit clearer, and in a way consistent with the description of similar failure for RAS as described in PRC-012-2. This would avoid any potential debate over the definition of redundancy - in order to determine what is a “non-redundant” component, one needs to define what does and does not constitute redundancy in this context (e.g., What about a backup relay that performs similar functions, but is not exactly the same? What about a duplicate relay with slightly different settings, or configured in the system in such a way that it responds a little slower? What if there is a “redundant” trip coil in a breaker, but it’s not hooked up?). It would also clarify that for the case of multiple non-redundant components in a particular Protection Scheme, that the simultaneous failure of all non-redundant components is required to be considered (we assume the intent in such a case would be to consider failure of each non-redundant component one at a time).

As provided in previous comments periods, Exelon recommends removing communication systems from footnote 13 in the revised standard. The SPCS concluded that the analysis of communications systems with regard to single points of failure did not pose enough of a risk for inclusion in footnote 13. As noted in the “Consideration of Comments”, the SDT “augmented the SAMS/SPCS recommendations to include the reference to the subset of communications systems that are part of a communication-aided Protection System”. By doing this, the inclusion of communications systems extends beyond the scope of the SAR to “[c]onsider the recommendations for modifying NERC Reliability Standard TPL-001-4 (Transmission System Planning Performance Requirements) as identified in the SPCS and SAMS report.”

Requirement R2.7 should be revised to reference Requirement R2, Parts 2.1.4 and 2.4.4 and not Requirement R2, Part 2.4.3 based upon the currently proposed draft. Requirement 2.4.4 is specific to the sensitivity studies.

The SDT should consider aligning the language in Requirements R3, Part 3.5 and R4, Part 4.2: “If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.”

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

| **Response** |
|---|
| |

**5. Are the proposed revisions to TPL-001-4 along with the Implementation Plan a cost effective way of meeting the FERC directives in Order No. 786 and Order No. 754?**

| **Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6** | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| Please see response to #4. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| **Joe McClung - JEA - 3,5 - FRCC, Group Name** JEA Voters | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| Not only are some of the proposed changes from the SDT out-of-scope from the SAR and cost-prohibitive such as the addition of planning event P8, but the added reliability benefit is marginal for such a rare event compared to the cost, logistics, coordination and the aggressive implementation schedule that will be needed to achieve the desired outcome. Additionally, the implementation plan to achieve performance requirements for the modified P5 with single points of failure definitely needs an industry input. JEA is not disagreeing with the changes for P5 (please see our prior comments) but a more pragmatic approach is needed to address the industry concerns with CAP implementation to meet the Commission's directives especially in Order No. 754.<br><br>**Suggestion**: Remove the proposed P8 event along with the associated CAP and the Implementation Plans. For the new CAPs with the newly-added studies for P5 planning events only with single points of failure on Protection System, JEA recommendations for NERC to survey the industry (PCs, TPs and Facility owners) with another **Request for Data Under Section 1600 of the NERC Rules of Procedure** for a more realistic implementation schedule. Or alternatively, request and track the implementation plans for CAPs for such P5 events from the industry as part of the annual **ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP)**. | |
| Likes 1 | JEA, 5, Babik John |
| Dislikes 0 | |
| **Response** | |
| | |

| **Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 6** | |
|---|---|
| **Answer** | No |
| **Document Name** | |

| | |
|---|---|
| **Comment** | |
| These are not cost effective because it will create additioanl studies that will have minimal to no benefit for planning purposes. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| BPA feels that it is not cost effective to plan and construct a project for a planned outage of short duration that would be coordinated ahead of time according to outage planning processes (development of an operating plan) and would not be planned during peak seasons. It would also not be cost effective to plan and construct a project for a planned outage of short duration when planned outages of the same facility are not expected again in the foreseeable outage planning timeframes. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Kelsi Rigby - APS - Arizona Public Service Co. - 5** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| AZPS notes that it believes that, with the exception of Requirement 1, Part 1.1.2, the proposed TPL-001-4 is cost effective. As stated in response to Question 2 above, AZPS recommends that a definitive time period of “more than 3 months” be added to Requirement 1, Part 1.1.2. The inclusion of outages that are 3 months or less creates unnecessary study burden with little or no added reliability benefit and the currently proposed criteria increases the potential for inconsistency relative to planning assessments, which inconsistency increases costs while eroding the overall reliability benefit anticipated. Please refer to AZPS’s response to Question 2 for additional details. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC** | |

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

Absolutely NOT.  The SDT has not presented a solid cost effective analysis on the proposed changes leaving industry seriously questioning the process and the amount of work that would be potentially created by these changes and the minimal return on investment.

ADDITIONAL COMMENTS

1. In reviewing the edits to R1.1.2, I'm still concerned about the vagueness of those outages that must be modeled and whether such consultation will now require the RC to meet with each TP and PC separately within the FRCC on an annual basis.
2. Given the changes to requirement R1.1.2, we believe there needs to be applicability in the standard to the Reliability Coordinator and not just the PC and TP.  Also, since the SDT struck out the duration of six months in R1.1.2, there should be a time-frame around the length of transmission outages given some outages are only for a few hours, some for a day, a week, a month, etc., that may not be covering the year, season, or load level entities are assessing.

(3) Regarding the edits to R1.1.2, what happens if the RC, TP, or PC disagree as to which outages to include in the System models?  Is it acceptable to the SDT if procedures are written whereby not all entities are in agreement with which outages to include?

(4) In R2.1.5, the SDT changed "studied" to "assessed".  Can the SDT provide background on what is now expected with the term "assessed" differently than what was performed under the term "studied"?

(5) In R2.4.5, can the SDT elaborate on what is expected in, and how detailed, an entity's spare equipment strategy should be that is needed for TPL-001-5?

(6) In R2.4.5, the wording "The analysis shall simulate the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment" opens entities up to major compliance interpretation issues as it's not certain that entities will evaluate ALL conditions that the System is expected to experience in our Planning Assessment, this needs to be further clarified by the SDT.

(7) P5, and footnote 13, was modified to cover non-redundant components of a Protection System.  This is a substantial additional burden onto entities.  Seminole requests the team to perform a cost effectiveness study concerning these additional edits.

(8) In the Cost effectiveness Document updated(3/8/2018), pg 3  Footnote 13-(2 single-station DC supply that is not monitored for both low voltage and open circuit, with alarms centrally monitored (i.e., reported within 24 hours of detecting an abnormal condition to a location where corrective action can be initiated), How is this not a single point of failure?

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Jeff Landis - Platte River Power Authority - 3**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

PRPA supports JEA comments.

Not only are some of the proposed changes from the SDT out-of-scope from the SAR and cost-prohibitive such as the addition of planning event P8, but the added reliability benefit is marginal for such a rare event compared to the cost, logistics, coordination and the aggressive implementation schedule that will be needed to achieve the desired outcome. Additionally, the implementation plan to achieve performance requirements for the modified P5 with single points of failure definitely needs an industry input. JEA is not disagreeing with the changes for P5 (please see our prior comments) but a more pragmatic approach is needed to address the industry concerns with CAP implementation to meet the Commission's directives especially in Order No. 754.

Suggestion: Remove the proposed P8 event along with the associated CAP and the Implementation Plans. For the new CAPs with the newly-added studies for P5 planning events only with single points of failure on Protection System, JEA recommendations for NERC to survey the industry (PCs, TPs and Facility owners) with another Request for Data Under Section 1600 of the NERC Rules of Procedure for a more realistic implementation schedule. Or alternatively, request and track the implementation plans for CAPs for such P5 events from the industry as part of the annual ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP).

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Haley Sousa - Public Utility District No. 1 of Chelan County - 5, Group Name** Chelan PUD

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

The P8 event creates a major burden to entities to mitigate Extreme Events. This is not cost effective due to the rarity of events and the added reliability benefit is marginal compared to the cost, logistics, coordination and the aggressive implementation schedule needed to achieve the desired outcome.

Additionally, the implementation plan to achieve performance requirements for the modified P5 with single points of failure definitely needs an industry input. CHPD is not disagreeing with the changes for P5 (please see our prior comments) but a more pragmatic approach is needed to address the industry concerns with CAP implementation to meet the Commission's directives especially in Order No. 754.

Suggestion: Remove the proposed P8 event along with the associated CAP and the Implementation Plans. For the new CAPs with the newly-added studies for P5 planning events only with single points of failure on Protection System, CHPD recommends for NERC to survey the industry (PCs, TPs and Facility owners) with another Request for Data Under Section 1600 of the NERC Rules of Procedure for a more realistic implementation schedule. Or alternatively, request and track the implementation plans for CAPs for such P5 events from the industry as part of the annual ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP).

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Fred Frederick - Southern Indiana Gas and Electric Co. - 3**

| | |
|---|---|
| **Answer** | No |

| | |
|---|---|
| **Document Name** | |
| **Comment** | |
| The proposed revision is potentially not cost effective depending on the clarification requested in question 4. We feel that more explanation/guidance is needed to address what is and isn't included in the "components of a Protection System." The research to determine which of these components is a single point of failure, and what the delayed clearing time would be, is potentially quite expansive. We would like to have a more clear idea of the scope of this work and how the impacts differ from P4 and the existing P5 contingencies. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Shawn Abrams - Santee Cooper - 1** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| The inclusion of a new planning event that requires a CAP goes against Section 215 of the Federal Power Act which expressly prohibits NERC from promulgating standards which would require utilities to enlarge facilities or construct new transmission or generation. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Russel Mountjoy - Midwest Reliability Organization - 10, Group Name** MRO NSRF | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| Table 1, Footnote 13.d is not expected to be cost-effective as written. While the Standard Drafting Team chose wording to offer some flexibility for applicable entities to meet the requirements of Footnote 13.d, the vagueness of the current language is expected to lead to differences in interpretations between applicable entities and regulators. To avoid the risk of being judged non-compliant, applicable entities will need to assume a very liberal interpretation of Footnote 13.d and engage in an immense scope of work, which may find little or no adverse BES reliability impacts. The investigation of existing control wiring and development of applicable contingency descriptions are expected impose a very large demand on labor resources. We propose that the SDT defer imposing a “non-redundant control circuitry” requirement on the industry until the scope of work can be limited to cost-effective level through risk-based inclusion/exclusion criteria and more clear definition of applicable control circuitry.<br><br>If the Standard Drafting Team (SDT) does not add the proposed Footnote 14 in Table 1 (which makes it clear that TPs and PCs can perform the 3-phase fault simulations in a way that avoids unnecessary and duplicative SLG fault simulations), then the proposed standard may lead entities and | |

regulators to interpret that a significant amount of unnecessary and duplicative P5 event analysis is required for compliance. The unnecessary and duplicative P5 event analysis would not be cost-effective.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

NIPSCO agrees with JEA comments

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Marty Hostler - Northern California Power Agency - 5**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

See JEAs response.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name** OKGE

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

Proposed TPL-001-4 is not the most cost-effective way of meeting the FERC directives because the standard will compel the PC and TP to expend additional costs and staff resources to prepare and implement a CAP for P8 events, which is not required by Order No. 754. Because P8 events are considered to be rare occurences in the industry, requiring a CAP is not a effective use of resources. The following conclusion statement in the Joint Report on Order 754 supports this position: “This concern (the study of protection system single points of failure) is appropriately addressed as an extreme event in TPL-001-4 Part 4.5” *See Order 754 Assessment at p. 11.*

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

LADWP does not agree with majority of the change. There is no evidence that the changes will be more cost effective. Unitl the new proposed is agreed and approved, it would be hard to made a comment on this question.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Dennis Sismaet - Northern California Power Agency - 6**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

Please see JEA's comments.

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|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

MEC supports NSRF comments. In addition, the zero defect compliance work to maintain perfect protection system drawings and change management is significant with little additional actual system reliability gain due to the rare probability of a delayed cleared fault combined with a single-point-of-failure protection component failure that isn't already known. NERC and industry should work together to seek a better risk based strategy to focus on important substations. Examples could be the use of voltage class levels similar to FAC-003 (200kV and above or as identified by the RC / PA), high fault current levels similar to PRC-002, or number of transmission interconnections similar to the FERC Order 754 effort.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Ellen Oswald - Midcontinent ISO, Inc. - 2**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

Table 1, Footnote 13.d is not expected to be cost-effective as written. While the Standard Drafting Team chose wording to offer some flexibility for applicable entities to meet the requirements of Footnote 13.d, the vagueness of the current language is expected to lead to differences in interpretations between applicable entities and regulators. To avoid the risk of being judged non-compliant, applicable entities will need to assume a very liberal interpretation of Footnote 13.d and engage in an immense scope of work, which may find little or no adverse BES reliability impacts. The investigation of existing control wiring and development of applicable contingency descriptions are expected impose a very large demand on labor resources. We propose that the SDT defer imposing a “non-redundant control circuitry” requirement on the industry until the scope of work can be limited to cost-effective level through risk-based inclusion/exclusion criteria and more clear definition of applicable control circuitry.

If the Standard Drafting Team (SDT) does not add the proposed Footnote 14 in Table 1 (which makes it clear that TPs and PCs can perform the 3-phase fault simulations in a way that avoids unnecessary and duplicative SLG fault simulations), then the proposed standard may lead entities and regulators to interpret that a significant amount of unnecessary and duplicative P5 event analysis is required for compliance. The unnecessary and duplicative P5 event analysis would not be cost-effective.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Mike Smith - Manitoba Hydro - 1, Group Name** Manitoba Hydro

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

The changes are forcing the industry to invest to protect against rare three-phase faults coupled with protection system failure. This should remain as an extreme event and allow the TP/PC to decide whether mitigating possible Casading is cost effective.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

No, Although the drafting team has identified "adding redundant protection improves the relialbity of the Bulk Power System at lower costs than other contructions projects" there exists significant costs for associated component of the protections system.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Douglas Johnson - American Transmission Company, LLC - 1**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

Table 1, Footnote 13.d is not expected to be cost-effective as written. While the Standard Drafting Team chose wording to offer some flexibility for applicable entities to meet the requirements of Footnote 13.d, the vagueness of the current language is expected to lead to differences in interpretations between applicable entities and regulators. To avoid the risk of being judged non-compliant, applicable entities will need to assume a very liberal interpretation of Footnote 13.d and engage in an immense scope of work, which may find little or no adverse BES reliability impacts. The investigation of existing control wiring and development of applicable contingency descriptions are expected impose a very large demand on labor resources. We propose that the SDT defer imposing a “non-redundant control circuitry” requirement on the industry until the scope of work can be limited to cost-effective level through risk-based inclusion/exclusion criteria and more clear definition of applicable control circuitry.

If the Standard Drafting Team (SDT) does not add the proposed Footnote 14 in Table 1 (which makes it clear that TPs and PCs can perform the 3-phase fault simulations in a way that avoids unnecessary and duplicative SLG fault simulations), then the proposed standard may lead entities and regulators to interpret that a significant amount of unnecessary and duplicative P5 event analysis is required for compliance. The unnecessary and duplicative P5 event analysis would not be cost-effective.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

| Response | |
|---|---|
| | |
| **Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Randy Hahn, Ocala Utility Services, 3; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name** FMPA | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

1. The required analysis of all scheduled outages in the near term horizon is not cost-effective, as it will result in many studies being run without meaningful results and/or with time spent "proving the negative".

2. Introducing a new type of event in Planning Event P8 creates unnecessary compliance burden and is illogical.  Furthermore, it opens up industry to additional illogical changes to a planning standard that was generally working pretty well before these changes.

3. Flatly requiring P1/P2 events be studied in stability is likely to simply create busy work since an entity may (not a guarantee – based on details specific to each facility and engineering judgment) determine that a P4 or P5 is more appropriate to simulate, but would be required to run the P1 or P2 event regardless (e.g. in addition to those events the entity feels are best to study).

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |

Table 1, Footnote 13.d is not expected to be cost-effective as written. While the Standard Drafting Team chose wording to offer some flexibility for applicable entities to meet the requirements of Footnote 13.d, the vagueness of the current language is expected to lead to differences in interpretations between applicable entities and regulators. To avoid the risk of being judged non-compliant, applicable entities will need to assume a very liberal interpretation of Footnote 13.d and engage in an immense scope of work, which may find little or no adverse BES reliability impacts. The investigation of existing control wiring and development of applicable contingency descriptions are expected impose a very large demand on labor resources. We propose that the SDT defer imposing a "non-redundant control circuitry" requirement on the industry until the scope of work can be limited to cost-effective level through risk-based inclusion/exclusion criteria and more clear definition of applicable control circuitry.

If the Standard Drafting Team (SDT) does not add the proposed Footnote 14 in Table 1 (which makes it clear that TPs and PCs can perform the 3-phase fault simulations in a way that avoids unnecessary and duplicative SLG fault simulations), then the proposed standard may lead entities and regulators to interpret that a significant amount of unnecessary and duplicative P5 event analysis is required for compliance. The unnecessary and duplicative P5 event analysis would not be cost-effective.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

See comments from MRO NSRF.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6; - Michael Brytowski**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

GRE agrees with the MRO NSRF and ACES comments.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

To determine if something is cost-effective, the analysis must consider alternatives to achieve a measurable outcome.

| |
|---|
| The FERC directives are narrowly drafted without significant alternatives to fulfill their outcomes. Reflected in the proposed revisions and Implementation Plan are the directives' narrow framework and, as such, a meaningful analysis of the revisions and Plan's cost-effectiveness is indeterminable. |

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

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|---|
| **Response** |
| |
| **Scott Miller - Scott Miller On Behalf of: David Weekley, MEAG Power, 3, 5, 1; Roger Brand, MEAG Power, 3, 5, 1; Steven Grego, MEAG Power, 3, 5, 1; - Scott Miller, Group Name** MEAG Power |

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

| |
|---|
| **Comment** |
| Not only are some of the proposed changes from the SDT out-of-scope from the SAR and cost-prohibitive such as the addition of planning event P8, but the added reliability benefit is marginal for such a rare event compared to the cost, logistics, coordination and the aggressive implementation schedule that will be needed to achieve the desired outcome. Additionally, the implementation plan to achieve performance requirements for the modified P5 with single points of failure definitely needs an industry input. We do not disagree with the changes for P5 (please see our prior comments) but a more pragmatic approach is needed to address the industry concerns with CAP implementation to meet the Commission's directives especially in Order No. 754.<br><br>Suggestion: Remove the proposed P8 event along with the associated CAP and the Implementation Plans. For the new CAPs with the newly-added studies for P5 planning events only with single points of failure on Protection System, Rrecommend NERC survey the industry (PCs, TPs and Facility owners) with another Request for Data Under Section 1600 of the NERC Rules of Procedure for a more realistic implementation schedule. Or alternatively, request and track the implementation plans for CAPs for such P5 events from the industry as part of the annual ERO Enterprise Compliance Monitoring and Enforcement Program (CMEP). |

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

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|---|
| **Response** |
| |
| **Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name** Tennessee Valley Authority |

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

| |
|---|
| **Comment** |
| TVA supports JEA's comments. We believe a three-phase fault including protection system failure would have an extremely low probability of occurring. Requiring implementation of actions to prevent these extremely rare events would cause a large and unnecessary financial burden with little benefit to our system reliability. |

| | |
|---|---|
| Likes 0 | |

| | |
|---|---|
| Dislikes 0 | |
| **Response** | |
| | |
| **Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| The proposed revisions to this Standard would add significant resource and financial burden to TOs and GOs. Recommend for the SDT to evaluate System performance issues thru planning studies prior to making Corrective Action Plans (CAPs) mandatory in the Implementation Plan. This would provide time for the SDT to evaluate the impact and cost implications that these new Requirements have on industry. After an evaluation is done, then the SDT can determine what CAPs would be required and reduce the financial impacts to industry by utilizing a separate Implementation Plan. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6 - WECC** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| SCE submitted comments regarding the cost-effectiveness of the proposed revisions to TPL-001-4 during a previous period. SCE's opinion has not changed and, consequently, SCE would like to reiterate our feedback from the previous comment period (i.e., the comment period ending 10/23/2017). | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Brian Van Gheem - ACES Power Marketing - 6, Group Name** ACES Standards Collaborators | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| 1. We believe a more cost effective way approach to meeting the FERC directives exists. The proposed changes should allow registered entities the flexibility to determine how they will address this BES reliability risk. The currently proposed solution requires a registered entity to conduct a duplicative contingency analysis for a three-phase fault that is less likely to occur than a single-phase-to-ground fault under similar conditions. | |

2. The “dc supply” reference to open circuit within Footnote 13c could require an entity to purchase additional equipment based on the accepted configuration. We recommend revising the footnote to only consider when the dc supply is not monitoring or reporting abnormal DC voltages.
3. We thank you for this opportunity to comment.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name** SPP Standards Review Group

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

Proposed TPL-001-4 is not the most cost-effective way of meeting the FERC directives because the standard will compel the PC and TP to expend additional costs and staff resources to prepare and implement a CAP for P8 events, which are rare occurences in the industry and not required by Order No. 754.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name** Seattle City Light Ballot Body

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

City Light supports JEA comments.

| | |
|---|---|
| Likes 0 | |
| Dislikes 0 | |

**Response**

**Jamie Monette - Allete - Minnesota Power, Inc. - 1**

| | |
|---|---|
| **Answer** | No |
| **Document Name** | |

**Comment**

| | |
|---|---|
| **As proposed, the revisions are overly-complicated and will require a considerable amount of additional work for defining, modeling, and analyzing new contingencies. Further, if corrective actions are required for the proposed P8 event, there is little real payback due to the extreme unlikelihood of the event.** | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| There is some correlation between FERC directives in Order NO. 786 and Order No. 754 such as a Tranmission Planner assessing their portion of the Bulk Electric System (BES) for locations at which a three phase fault accompanied by a protection system failure could result in a potential reliability risk (Order No. 754) and the expansion on Protection System Failures versus Relay Failures (Order No. 786). However, EEI summarized it best by stating in Order No. 786 (p. 46), "...expanding planning studies to include all manner of protection system failures could create a scenario where planners would have to conduct unlimited and unbound studies."<br><br>The potential for unlimited studies to include all manner of protection system failures is not a cost effective way of meeting both FERC directives. This new revision expands the purview from relay failure to failure of all protection system components. Additionally, this requirement (and its predecessor) required assessments of entire system unlike the limited ones per FERC order 754. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Teresa Cantwell - Lower Colorado River Authority - 5** | |
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| See comments in response to question 2. The development of a contingency set with acceptable system adjustments would be more efficient than requiring seperate cases be developed. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

| Faz Kasraie - Faz Kasraie On Behalf of: Mike Haynes, Seattle City Light, 1, 4, 5, 6, 3; - Seattle City Light - 5 - WECC | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Hasan Matin - Orlando Utilities Commission - 2 - FRCC** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| OUC would recommend providing some guidelines in order to guide the discussion on how to solve issues found under new Planning Event 8, such as recommending Zone 2 or Zone 3 protection where applicable (if acceptable though testing) or the addition of dual and separate DC sources. Guidelines on what actions to take and when to take them (along with cooridinating these upgrades with the company's protection group) would help further keep the revisions cost-effective by providing a methodology of least cost options to higher cost options. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Quintin Lee - Eversource Energy - 1, Group Name** Eversource Group | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| Yes if the clarification to Requirement 1, Part 1.1.2 is made | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Neil Swearingen - Salt River Project - 1,3,5,6 - WECC** | |

| | |
|---|---|
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| The lead time provided in the Implementation Plan allows entities to meet compliance in a cost-effective manner. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Robert Ganley - Long Island Power Authority - 1** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| While the proposed revisions to TPL-001-4 along with the Implementation Plan may be a cost effective way of meeting the FERC directives in Order No. 786 and Order No. 754 in terms of corrective action plans, the proposed revisions will present a very significant burden on Planning and Engineering staffs to investigate and identify “non-redundant” components of a Protection System. This incremental burden will have adverse cost impacts. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Jeffrey DePriest - DTE Energy - Detroit Edison Company - 3,4,5, Group Name** DTE Electric | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |

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|---|---|
| **RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **John Seelke - LS Power Transmission, LLC - 1** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name** PPL NERC Registered Affiliates | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Michael Jones - National Grid USA - 1, Group Name** National Grid | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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|---|---|
| **Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name** Southern Company | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name** RSC no Hydro One, NYISO and Eversource | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |
| **Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF** | |
| **Answer** | |
| **Document Name** | |
| **Comment** | |

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|---|
| No comment or opinion on cost effectiveness. |

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| Likes 0 | |
| Dislikes 0 | |

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| **Response** |
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| **Rachel Coyne - Texas Reliability Entity, Inc. - 10** | |
| **Answer** | |
| **Document Name** | |
| **Comment** | |
| Texas RE does not have comments on this question. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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|---|---|
| **Richard Vine - California ISO - 2** | |
| **Answer** | |
| **Document Name** | |
| **Comment** | |
| No comment | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
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| **Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2** | |
| **Answer** | |
| **Document Name** | |
| **Comment** | |
| No response or comments. | |

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| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

***Comments received from APPA***

**Questions**

1. Do you agree with the creation of the proposed P8 event?

☐ Yes
x☐ No

Comments: APPA concurs with the JEA comments that the addition of the P8 event is beyond what was in the Standards Authorization Request (SAR).

2. Do you agree with the changes to TPL-001-4 Requirement 1, Part 1.1.2, in order to meet the FERC directive in Order No. 786?

y☐ Yes
☐ No

Comments:

3. Do you agree with the proposed implementation plan?

☐ Yes
x☐ No

Comments: APPA believes the 36 month period for the proposed standard to be effective is appropriate as is the 24 month period for development of the CAP. However, we do endorse the overall implementation plan and support the reasoning for that lack of support provided in JEA's comments. Similarly, we support the JEA suggestion to remove the proposed P8 event and its associated CAP and seek industry feedback on a more feasible implementation plan.

4. Do you agree with the proposed revisions to TPL-001-4?

☐ Yes
x☐ No

Comments: APPA believes that the proposed revisions to TPL-001-4, especially the inclusion of P8 is not workable and supports the JEA comments and suggestions.

5. Are the proposed revisions to TPL-001-4 along with the Implementation Plan a cost effective way of meeting the FERC directives in Order No. 786 and Order No. 754?

   ☐ Yes
   x☐ No

   Comments: APPA believes the proposed revisions and implementation plan will not result in a cost effective way to meet the FERC directives in Order No. 786 and Order No. 754. The inclusion of event P8 is the driver for increasing the costs of the proposed standard. Importantly, the increased costs are not commensurate with a material improvement in reliability.

   Public power endorses the JEA comments and suggestions.