

Consideration of Comments

Project Name:	2015-10 Single Points of Failure TPL-001-5
Comment Period Start Date:	2/23/2018
Comment Period End Date:	4/23/2018
Associated Ballot:	2015-10 Single Points of Failure TPL-001-5 AB 2 ST 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.

All comments submitted can be reviewed in their original format on the [project page](#).

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

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					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
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Tara Lightner	Sunflower Electric Power Corporation	1	SPP RE
					Shari Heino	Brazos Electric Power	1,5	Texas RE

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Cooperative, Inc.		
					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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
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
					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	3	WECC

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						of Chelan County		
					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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					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
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	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Company Services, Inc.					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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
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
					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	7	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Reliability Council		
					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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Daniel Grinkevich	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					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	2	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						System Operator		
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 Dam 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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
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
					John Rhea	OGE Energy - Oklahoma Gas	5	SPP RE

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						and Electric Co.		

General Summary

The SDT appreciates the comments submitted. Overwhelmingly, the industry response to the proposed Table 1 P8 Event was negative. The SDT considered the weight of the industry responses rejecting the proposed addition to the Planning Events and has removed it from the draft TPL-001-5 Reliability Standard.

The SDT believes it is important to reiterate that the industry has been aware of concerns about Protection System component single point-of-failure (SPF) and corresponding risks to the BES since as early as the 30 March 2009 NERC Alert. Further, it was clear from the SPCS and SAMS report, following the data collection and assessment in support of FERC Order No. 754, that SPF reliability concerns were substantiated. The draft TPL-001-5 language proposed by the SDT was consistent with how other identified risks to reliability are incorporated into the Transmission System Planning standard, including similar assessments of low probability events (e.g., breaker failure).

A SPF in a Protection System is a wholly-preventable risk to the BES. Likewise, existing Protection System designs, as well as future ones can be made to assure that SPF is not a concern. Faults, conversely, are and will remain an inherent risk to the Transmission System. The SDT believes that single line-to-ground (SLG) fault migration into a three-phase (3ph) fault is a very real phenomenon, especially considering the Delayed Clearing of the initiating fault that may arise due to a SPF in a Protection System. In other words, today it is not only probable but certain that portions of the BES protected by Protection System with SPF will experience, when a SLG fault initiates, the evolution of a SLG-to-3ph fault, given significant durations before backup protection initiates.

The locations of SPF can be identified, simulated under faulted conditions, assessed for impacts to System performance, and solutions identified; each of which the planning entities can play a meaningful role in achieving. The SDT evaluated numerous alternatives and ultimately proposed to industry multiple options for TPL-001-5 to elevate the Contingency event that represents a 3ph fault plus a failure of a non-redundant component of a Protection System:

1. Maintain 3ph fault + SPF in Protection System event in Table 1 Stability Performance Extreme Events, but require Corrective Action Plan (CAP) when Cascading identified.
[TPL-001-5 Draft #1, Industry Comment period: 04/25/17 - 05/24/17]
2. Maintain 3ph fault + SPF in Protection System event in Table 1 Stability Performance Extreme Events; do not require a CAP, but do require stricter actions than typical Extreme Events when Cascading identified.
[TPL-001-5 Draft #2, Industry Comment period: 09/08/17 - 10/23/17]

- 3. Move 3ph fault + SPF in Protection System event to Table 1 Steady State & Stability Performance Planning Events as P8 Event; require a CAP, but maintain the System performance requirement as Cascading.
[TPL-001-5 Draft #3, Industry Comment period: 02/23/18 - 04/23/18]

Each of these options were rejected by industry, despite the SDT attempts to convey the reliability concept that SPF in a Protection System is preventable and to emphasize that the severity of an event’s impact must temper the tendency to diminish its importance because it is perceived to be unlikely. The SDT has, therefore, made no change to the existing evaluation of 3ph fault in the Table 1 Stability Performance Extreme Events, except to separate breaker failure from the SPF in Protection System event.

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	
<p>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”).</p> <p>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.</p>	

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	1	JEA, 5, Babik John
Dislikes	0	
Response		
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.		
Silvia Mitchell - NextEra Energy - Florida Power and Light Co. - 6		
Answer	No	
Document Name		
Comment		

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.

Likes 0

Dislikes 0

Response

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

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

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

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

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

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

Likes 0

Dislikes 0

Response

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

Jeff Landis - Platte River Power Authority - 3

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 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 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

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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

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

Thomas Foltz - AEP - 5

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.

Likes	0
Dislikes	0
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
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.	
Likes	0
Dislikes	0
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
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.

Likes 0

Dislikes 0

Response

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

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

Answer

No

Document Name

Comment

I support comments submitted by the MRO NERC Standards Review Forum

Likes 0

Dislikes 0

Response

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

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-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.

Likes	0
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Dislikes	0
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Response

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

Marty Hostler - Northern California Power Agency - 5

Answer	No
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Document Name	
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Comment

See JEAs response.

Likes	0
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Dislikes	0
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Response

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

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

Answer	No
Document Name	
Comment	
<p>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.</p> <p>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.</p>	
Likes	0
Dislikes	0
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
Answer	No
Document Name	
Comment	

The proposed addition of the P8 in Table 1 is beyond the standard requirements. The possibility of this event occurring is very remote. Requirement R4.3 (the deleted portion) should be kept in the standard. The proposed changes do not address any current issues or concerns based on the past history. The changes on the remedial action scheme seem to be appropriate.

Likes 0

Dislikes 0

Response

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

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

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-redundant 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.

Likes 0

Dislikes 0

Response

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

Dennis Sismaet - Northern California Power Agency - 6

Answer

No

Document Name	
Comment	
Please see JEA's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
MEC supports NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
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.

Likes	0
Dislikes	0
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
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.

Likes	0
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Dislikes	0
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Response

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

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
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Document Name	
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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 the Flppst 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.

Likes	0
Dislikes	0
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
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.

Likes	0
Dislikes	0
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
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-phase fault with a protection system 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.

Likes 0

Dislikes 0

Response

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

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.

Likes	0
Dislikes	0
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
John Bee - Exelon - 3	
Answer	No
Document Name	
Comment	
See Exelon TO Utilities Comments	
Likes	0
Dislikes	0
Response	
<p>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 FMMPA</p>	
Answer	No
Document Name	FMMPA_2015-10_Unofficial_Comment_Form_2018423_2_.docx
Comment	
FMMPA 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 analyze 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 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”.

Likes	0
Dislikes	0
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No

Document Name	
Comment	
<p>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.</p> <p>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.</p>	
Likes	0
Dislikes	0
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
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	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
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	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
Robert Ganley - Long Island Power Authority - 1	
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.

Likes	0
Dislikes	0

Response

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

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
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Document Name	
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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 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*” (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.

Likes 0

Dislikes 0

Response

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

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

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.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.	
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	

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4

Answer No

Document Name

Comment

See comments below.

Likes 0

Dislikes 0

Response

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

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

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

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 categorize 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 contingencies 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 Coordinator (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

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

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

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw

Answer

No

Document Name	
Comment	
<p>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.</p>	
Likes	0
Dislikes	0
Response	
<p>Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.</p>	
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	
Thank you for your comment.	
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 impedance 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		
Thank you for your comments.		
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		
Thank you for your comments.		
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	
Thank you for your comments.	
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	
Thank you for your comments.	
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.

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

Thank you for your comments.

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

Answer

Yes

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.

To remove the performance requirements for instability and islanding for a P8 event, ERCOT suggests the following wording changes to Condition (a):

(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

Thank you for your comments.

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	
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	
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-Quebec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
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	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 fault with a protection system failure is low enough that it does not warrant a planning 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

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

Richard Vine - California ISO - 2

Answer

Document Name

Comment

The creation of the proposed P8 event raises the following issues:

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.

To remove the performance requirements for instability and islanding for a P8 event, we suggest the following wording changes to Condition (a):

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

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

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 impracticable 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 separate 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

The SDT agrees that analyses conducted for Table 1 Planning Events (P3 and P6) result in the same topology as modeling a known planned outage and then simulating P1 events. While the resultant topology may be the same, the performance criteria are different. This comment illustrates that the analysis performed for Near Term Planning Assessments are often intertwined. The analysis performed for a P3 or P6 event, as well as results of previous planning assessments may be used to inform the planner about the effect of a known planned outages that are coupled P1 events. P5 are single-phase delayed-clearing contingencies. Modeling such contingencies may help in some, but not all scenarios – it is not a replacement for modeling maintenance outages with a single contingency on an adjacent facility.

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	
The SDT agrees that analyses conducted for Table 1 Planning Events (P3 and P6) result in the same topology as modeling a known planned outage and then simulating P1 events. While the resultant topology may be the same, the performance criteria are different. This comment illustrates that the analysis performed for Near Term Planning Assessments are is often intertwined. The analysis performed for a P3 or P6 event, as well as results of previous planning assessments may be used to inform the planner about the effect of a known planned outages that are coupled with P1 events.	
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	

FERC Order No. 786 was explicit that the TPL standard must address known maintenance outages in the Near Term Planning Horizon Assessments. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. The SDT recognizes a variety of factors such as MW load, topology, and facility ratings can be used as qualifying criteria for inclusion of know maintenance outages. However; other factors (as contained in the entity’s procedures) can also be employed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Part 2.1.3 and R2.4.3. As modified these requirements provide flexibility for companies to determine their own set of parameters, as a continent-wide procedure is not feasible nor does it address the needs of each region’s own unique system.

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 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 Electric 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.”

Likes 0

Dislikes 0

Response

Based on industry comments the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Requirement R2, Parts 2.1.3 and R2.4.3 enumerate criteria that can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. The selection of the know outage immediately follows Requirement R2, Parts 2.1.1 and 2.1.2 alleviating the need to the reference to Requirement R2, Parts 2.1.1 and 2.1.2; or Parts 2.4.1 and 2.4.2.

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.

Likes 0

Dislikes 0

Response

FERC Order No. 786 was explicit that the TPL standard must address known maintenance outages in the Near Term Planning Horizon Assessments. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. The SDT recognizes a variety of factors such as MW load, topology, and facility ratings can be used as qualifying criteria for inclusion of know maintenance outages. However; other factors (as contained in the entity’s procedures) can also be employed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Part 2.1.3 and R2.4.3. As modified these requirements provide flexibility for companies to determine their own set of parameters, as a continent-wide procedure is not feasible nor does it address the needs of each region’s own unique system.

Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4

Answer No

Document Name

Comment

See comments below.

Likes 0

Dislikes 0

Response

N/A

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

Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. A three-month outage duration would ignore the basic differences in network topology, load level, and load shape of each region and entity. Outage duration can be one of the criteria, but not the only criterion. Additionally, MW, load, topology, and facility ratings can also be used as qualifying criteria; however other factors (as contained in the entity’s procedures) can also be employed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3.

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

According to the FERC Order No. 786, there is no direct correlation between the time duration of an outage and system impact. A shorter duration outage may be more impactful to the system than a three-month outage. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. A three-month outage duration would ignore the basic differences in network topology, load level, and load shape of each region and entity. Outage duration can be one of the criteria, but not the only criterion. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3.

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 identify 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 maintenance 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 maintenance outage)

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

Likes	0
Dislikes	0

Response

FERC Order No. 786 did not limit outages to exclude generation outages. FERC incorporated language to be more inclusive, however, the SDT does recognize that most known outages are scheduled during the Real-Time and Operations Planning Horizon. FERC Order No. 786 was explicit in that known outages in the Near-Term Planning Horizon need to be addressed. Based on industry comments the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The SDT recognizes a variety of factors such as MW load, topology, and facility ratings can be used as qualifying criteria; however other factors (as contained in the entity’s procedures) can also be employed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3.

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

Answer	No
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Document Name	
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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 identify 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 maintenance outages for this assessment should be stated in the standard.

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

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:

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 maintenance outage)

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

Likes	0
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Dislikes	0
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Response

As noted in FERC Order No. 786, known outages in the Near Term Planning Horizon encompass more than just the subset of outages identified in Corrective Action Plans. The SDT provided clarity via Requirement R2, Parts 2.1.3 and R2.4.3 defining parameters that focus the selection of known outages. However, the parameters are not so specific as to limit only those associated with the Corrective Action Plans, as this assumption is not supported by the FERC Order No. 786.

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
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Document Name	
Comment	
<p>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.</p>	
<p>Texas RE’s principal concern with the proposed TPL-001 language, as currently drafted, is that it 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.</p>	
<p>A similar issue exists in the proposed TPL-001-5 Foot. 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.</p>	

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.

Likes 0

Dislikes 0

Response

The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. A three-month outage duration would ignore the basic differences in network topology, load level, and load shape of each region and entity. Outage duration can be one of the criteria, but not the only criterion. Additionally, MW, load, topology, and facility ratings can also be used as qualifying criteria; however other factors (as contained in the entity’s procedures) can also be employed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance

outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3.

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

The SDT assumes the pertinent portion of the KCP&L comment to question 4 is to “include language that will allow establishing the scope of contingencies in dynamics to a specific area local to the equipment”. To this issue the SDT has provided the capability to tailor the analysis to best fit a particular system. The SDT recognizes the range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. The regional differences reflect analysis that is tailored to best examine the system based on unique system characteristics. Accordingly the draft standard accommodates incorporating criteria such as MW, load, topology, and facility ratings to be used as qualifying criteria to identify which know planned outages are candidates for additional assessment as well as providing the flexibility to include other factors (as contained in the entity’s procedures). Past studies, local dynamics, as well as other P events (P6, P3) can be used as limiting factors tailored to each entity’s system when selecting known maintenance outages to include within the Near Term Planning Assessments and to put bounds on the extent of the assessment.

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

Previous planning assessments may be used to inform the planner about the effect of known planned outages that are coupled with P1 events. Additionally, information from analyses conducted for Table 1 Planning Events (P3 and P6) result in the same topology as modeling a known planned outage and then simulating P1 events. While the resultant topology may be the same, the performance criteria are different. This comment illustrates that the analysis performed for Near Term Planning Assessments are is often intertwined and may be used to inform the planner about the effect of a known planned outages in the near term planning horizon.

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

Based on industry comments the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. When doing so the SDT incorporated your changes in the revised wording including changing “schedule outage” to “known outage”, and “Transmission Planner and Planning Coordinator” to “Transmission Planner or Planning Coordinator”.

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

Based on industry comments the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity.

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

Based on industry comments the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. When doing so the SDT incorporated your changes in the revised wording including changing “schedule outage” to “known outage”, and “Transmission Planner and Planning Coordinator” to “Transmission Planner or Planning Coordinator”.

Leonard Kula - Independent Electricity System Operator - 2

Answer	No
Document Name	

Comment

We have two concerns with the proposed changes:

- 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 Reliability 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 Reliability 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.

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

Response

FAC-014 is not a planning standard, instead concentrating on system operating limits. FAC-014-02 R6 specifies identifying stability limits for a subset of TPL multiple contingencies. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Based on industry comments the SDT deleted

Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. As modified these requirements provide flexibility for companies to determine their own set of parameters, as a continent-wide procedure is not feasible nor does it address the needs of each region’s own unique system.

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

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 is 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].

Likes	0
Dislikes	0

Response

Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. When doing so, the SDT incorporated the changes in the revised wording including changing “schedule outage” to “known outage”, and “Transmission Planner and Planning Coordinator” to “Transmission Planner or Planning Coordinator”. FERC Order No. 786 was explicit that the TPL standard must address known maintenance outages in the Near Term Planning Horizon Assessments. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. The SDT recognizes a variety of factors such as MW load, topology, and facility ratings can be used as qualifying criteria for inclusion of known maintenance outages. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3. As modified these requirements provide flexibility for companies to determine their own set of parameters, as a continent-wide procedure is not feasible nor does it address the needs of each region’s own unique system.

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.

Likes 0

Dislikes 0

Response

Past studies as well as P3 and P6 events provide a foundation for establishing a list of what maintenance outages in the near-term need to be addressed. FERC Order No. 786 is explicit in that only known outages must be studied, not hypothetical outages. The range of industry

comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. A three-month outage duration would ignore the basic differences in network topology, load level, and load shape of each region and entity. Outage duration can be one of the criteria, but not the only criterion. Additionally, MW, load, topology, and facility ratings can also be used as qualifying criteria; however other factors (as contained in the entity’s procedures) can also be employed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3.

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.

Likes 0

Dislikes 0

Response

FERC Order No. 786 is explicit in that only known outages must be studied, not hypothetical outages. Additionally FERC order does include known outages of generation, transmission or protection system facilities in the near-term. FERC states that NERC has flexibility in addressing the identified concerns, and outlines several acceptable approaches. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Past

studies as well as P3 and P6 events provide a foundation for establishing a list of what maintenance outages in the near-term need to be addressed. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3.

Douglas Johnson - American Transmission Company, LLC - 1

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 is 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].

Likes 0

Dislikes 0

Response

Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. When doing so, the SDT incorporated the changes in the revised wording including changing “schedule outage” to “known outage”, and “Transmission Planner and Planning Coordinator” to “Transmission Planner or Planning Coordinator”. FERC Order No. 786 was explicit that the TPL standard must address known maintenance outages in the Near Term Planning Horizon Assessments. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. The SDT recognizes a variety of factors such as MW load, topology, and facility ratings can be used as qualifying criteria for inclusion of know maintenance outages. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3. As modified these requirements provide flexibility for companies to determine their own set of parameters, as a continent-wide procedure is not feasible nor does it address the needs of each region’s own unique system.

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

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.

Likes	0
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Dislikes	0
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Response

Based on industry comments the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. A three-month outage duration would ignore the basic differences in network topology, load level, and load shape of each region and entity. Outage duration can be one of the criteria, but not the only criterion. Additionally, MW, load, topology, and facility ratings can also be used as qualifying criteria; however other factors (as contained in the entity's procedures) can also be employed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3.

Ellen Oswald - Midcontinent ISO, Inc. - 2

Answer	No
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Document Name	
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Comment	
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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 is 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].

Likes 0

Dislikes 0

Response

Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. When doing so, the SDT incorporated the changes in the revised wording including changing “schedule outage” to “known outage”, and “Transmission Planner and Planning Coordinator” to “Transmission Planner or Planning Coordinator”. FERC Order No. 786 was explicit that the TPL standard must address known maintenance outages in the Near Term Planning Horizon Assessments. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. The SDT recognizes a variety of factors such as MW load, topology, and facility ratings can be used as qualifying criteria for inclusion of know maintenance outages. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3. As modified these requirements provide flexibility for companies to determine their own set of parameters, as a continent-wide procedure is not feasible nor does it address the needs of each region’s own unique system.

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

Answer

No

Document Name

Comment

MEC supports NSRF comments.

Likes 0

Dislikes 0

Response

Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. When doing so, the SDT incorporated the changes in the revised wording including changing “schedule outage” to “known outage”, and “Transmission Planner and Planning Coordinator” to “Transmission Planner or Planning Coordinator”. FERC Order No. 786 was explicit that the TPL standard must address known maintenance outages in the Near Term Planning Horizon Assessments. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. The SDT recognizes a variety of factors such as MW load, topology, and facility ratings can be used as qualifying criteria for inclusion of know maintenance outages. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3. As modified these requirements provide flexibility for companies to determine their own set of parameters, as a continent-wide procedure is not feasible nor does it address the needs of each region’s own unique system.

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

Answer	No
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Document Name	
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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	
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Dislikes 0	
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Response

Based on industry comments the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. A three-month outage duration would ignore the basic differences in network topology, load level, and load shape of each region and entity. Outage duration can be one of the criteria, but not the only criterion. Additionally, MW, load, topology, and facility ratings can also be used as qualifying criteria; however other factors (as contained in the entity’s procedures) can also be employed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting

known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Part 2.1.3 and 2.4.3.

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 Electric 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.”

Likes 0

Dislikes 0

Response

Based on industry comments the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Requirement R2, Parts 2.1.3 and 2.4.3 enumerate criteria that can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. The selection of the know outage immediately follows Requirement R2, Parts 2.1.1 and 2.1.2 alleviating the need to the reference to Parts 2.1.1 and 2.1.2; or Parts 2.4.1 and 2.4.2.

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).

Likes 0

Dislikes 0

Response

Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Requirement R2, Parts 2.1.3 and 2.4.3 enumerate criteria that can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments.

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

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.

Likes 0

Dislikes 0

Response

FERC Order No. 786 clarified that the TPL Near-Term Planning Assessment is a required and beneficial analysis. A six-month outage duration would ignore the basic differences in network topology, load level, and load shape of each region and entity. Outage duration can be one of the criteria, but not the only criterion. Additionally, MW, load, topology, and facility ratings can also be used as qualifying criteria; however other factors (as contained in the entity's procedures) can also be employed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3.

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

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 is 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 studied, 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].

Likes 0

Dislikes 0

Response

Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. When doing so, the SDT incorporated the changes in the revised wording including changing “schedule outage” to “known outage”, and “Transmission Planner and Planning Coordinator” to “Transmission Planner or Planning Coordinator”. FERC Order No. 786 was explicit that the TPL standard must address known maintenance outages in the Near Term Planning Horizon Assessments. The range

of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. The SDT recognizes a variety of factors such as MW load, topology, and facility ratings can be used as qualifying criteria for inclusion of known maintenance outages. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3. As modified these requirements provide flexibility for companies to determine their own set of parameters, as a continent-wide procedure is not feasible nor does it address the needs of each region's own unique system.

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..."

Likes 0

Dislikes 0

Response

The SDT has modified Requirement R2, Parts 2.1.3 and 2.1.4 for clarity, indicating that P3 and P6 in addition to past studies can be used as a foundation for establishing the list of known outages for further assessment.

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

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.

Likes	0
Dislikes	0

Response

Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Requirement R2, Parts 2.1.3 and 2.4.3 enumerate criteria that can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments.

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.

Likes 0

Dislikes	0
Response	
<p>FERC Order No. 786 clarified that the TPL Near-Term Planning Assessment is a required and beneficial analysis. Specifying particular outage duration would ignore the basic differences in network topology, load level, and load shape of each region and entity. Outage duration can be one of the criteria, but not the only criterion. Additionally, MW, load, topology, and facility ratings can also be used as qualifying criteria; however other factors (as contained in the entity’s procedures) can also be employed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3.</p> <p>FERC Order No. 786 did not limit outages to exclude dynamic assessments. FERC incorporated language to be more inclusive, however, the SDT does recognize that most known outages are scheduled during the Real-Time and Operations Planning Horizon.</p>	
Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC	
Answer	No
Document Name	
Comment	
<p>Tri-State partially agrees but has some reservations regarding the specific language and overlaps with existing P3 and P6 contingency categories.</p> <p>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.</p> <p>Requirement 1.1.2 effectively describes a category P3 or P6 contingency.</p>	
Likes	0
Dislikes	0
Response	

Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Requirement R2, Part 2.1.3 and 2.4.3 enumerate criteria that can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments.

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.

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

Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. A three-month outage duration would ignore the basic differences in network topology, load level, and load shape of each region and entity. Outage duration can be one of the criteria, but not the only criterion. Additionally, MW, load, topology, and facility ratings can also be used as qualifying criteria; however other factors (as contained in the entity’s procedures) can also be employed. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3.

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
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Document Name	
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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.

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	
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Dislikes 0	
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Response

Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Requirement R2, Parts 2.1.3 and 2.4.3 enumerate criteria that can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments.

John Seelke - LS Power Transmission, LLC - 1

Answer	No
Document Name	
Comment	
<p>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:</p> <p>“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.”</p> <p>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:</p> <p>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.</p> <p>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..</p> <p>LSPT’s proposed changes to 2.1.3 (and correspondingly to 2.4.3) will correct this unintended consequence:</p> <p>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.</p>	
Likes	0
Dislikes	0

Response

Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Requirement R2, Parts 2.1.3 and 2.4.3 enumerate criteria that can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments.

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.

Likes 0

Dislikes 0

Response

Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Requirement R2, Parts 2.1.3 and 2.4.3 enumerate criteria that can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments.

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

Dislikes 0

Response

Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3. Parts 2.1.3 and 2.4.3 enumerate criteria that can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments.

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer

No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
N/A	
David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
<p>As proposed, we believe that R1.1.2.1 involves the creation of hypothetical outages to evaluate and include in the transmission assessment.</p> <p>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.</p>	

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.

Likes 0

Dislikes 0

Response

FERC Order No. 786 is explicit in that only known outages must be studied, not hypothetical outages. FERC Order No. 786 did not limit outages to exclude generation outages. FERC incorporated language to be more inclusive, however, the SDT does recognize that most known outages are scheduled during the Real-Time and Operations Planning Horizon. FERC Order No. 786 was explicit in that known outages in the Near-Term Planning Horizon need to be addressed.

Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3. Parts 2.1.3 and 2.4.3 enumerate criteria that can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments, and to lessen the ambiguity of the FERC Order.

The SDT has incorporated language in Requirement R2, Parts 2.1.3 and 2.4.3 that provides flexibility for companies to determine their own set of parameters, as a continent-wide procedure is not feasible nor does it address the needs of each region's own unique system.

The SDT should not and cannot provide clarity behind the reasoning of FERC. The webinar question referenced in your comment was regarding using basecase adjustments prior to replicating P1 events, which is permitted. In the Webinar, one example of what is different between performance requirements of a P1 vs. P6 was given as “system adjustments are allowed”, another example of a difference between performance requirements is load drop is allowed for a P6 and not allowed for a P1. It should not be assumed that one example given in the webinar between performance requirements of a P1 vs. P6 is the only reason why a P6 is insufficient.

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

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.

Likes 0

Dislikes 0

Response

Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. Past studies as well as other P events (P6, P3) can be used as limiting factors in selecting known maintenance outages to include within the Near Term Planning Assessments. Examples of other factors to be considered are enumerated in Requirement R2, Parts 2.1.3 and 2.4.3.

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

Answer No

Document Name

Comment	
Likes 0	
Dislikes 0	
Response	
N/A	
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	
N/A	
Shawn Abrams - Santee Cooper - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

N/A	
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	
Thank you for your comments.	
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	
Thank you for your comments.	
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	
Thank you for your comment; the SDT has since corrected this error.	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	
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	
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	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
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	
faranak sarbaz - Los Angeles Department of Water and Power - 1,3,5,6	
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	
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

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

Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.

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

Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.

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

Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. With the removal of the P8 categories, the SDT believes that the 36-month timeframe for initial assessment period is sufficient. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.

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	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
See JEAs response.	
Likes	0
Dislikes	0
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
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	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
Please see JEA's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
MEC supports NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
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

Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. With the removal of the P8 categories, the SDT believes that the 36-month timeframe for initial assessment period is sufficient. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.

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

Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. With the removal of the P8 categories, the SDT believes that the 36-month timeframe for initial assessment period is sufficient. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.

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

Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.

John Bee - Exelon - 3

Answer

No

Document Name

Comment

See Exelon TO Utilities Comments

Likes 0

Dislikes 0

Response

Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.

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 FMMPA	
Answer	No
Document Name	
Comment	
FMMPA supports the comments of JEA on the implementation plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
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

Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. With the removal of the P8 categories, the SDT believes that the 36-month timeframe for initial assessment period is sufficient. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.

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

Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.

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

Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.

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	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
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.	
Likes	0
Dislikes	0
Response	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
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	
<p>KCP&L recommends extending to 60-months the preparation period prior to the effective date of the Standard.</p> <p>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.</p> <p>Concern</p> <p>The proposed Implementation Plan's time periods do not fully consider the differences in system sizes, complexity, and design elements.</p> <p>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.</p> <p>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:</p> <ul style="list-style-type: none">• Changing and updating contingency lists will extend beyond the 36-month period because of the complexity and size of the undertaking and required vetting. <p>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:</p> <ol style="list-style-type: none">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:<ul style="list-style-type: none">• 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

Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. With the removal of the P8 categories, the SDT believes that the 36-month timeframe for initial assessment period is sufficient. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.

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 Firm 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

Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline. In addition, by the time the TPL-001-5 becomes effective which is 36 months after the approval date TPL-001-4 would have met the 84-month period so there is no overlapping or confusion.

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.

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.

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, 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

Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.

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	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
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

TPL-001-5 footnote 13d was revised to include monitoring of trip coils.

Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. With the removal of P8 categories, the SDT believes that 24-month for developing Corrective Action Plan is sufficient. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.

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	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
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	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
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

Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.

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

Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.

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	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
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	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
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	
Thank you for your comment.	
Jamie Monette - Allele - 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	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	
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	
Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.	

Chris Scanlon - Exelon - 1, Group Name Exelon Utilities	
Answer	
Document Name	
Comment	
<p>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.</p>	
Likes 0	
Dislikes 0	
Response	
<p>Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.</p>	
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

Thank you for your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, the SDT has also added a diagram showing the timeline in the supporting documents.

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.

Likes 0

Dislikes 0

Response

The SDT agrees with some comments and revisions have been made to the draft standard.

Teresa Cantwell - Lower Colorado River Authority - 5

Answer

No

Document Name

Comment

See comments in response to question 2.

Likes 0

Dislikes 0

Response

The SDT agrees that analyses conducted for Table 1 Planning Events (P3 and P6) result in the same topology as modeling a known planned outage and then simulating P1 events. While the resultant topology may be the same, the performance criteria are different. This comment illustrates that the analysis performed for Near Term Planning Assessments are is often intertwined. The analysis performed for a P3 or P6 event, as well as results of previous planning assessments may be used to inform the planner about the effect of a known planned outages that are coupled P1 events. P5 are single-phase delayed-clearing contingencies. Modeling such contingencies may help in some, but not all scenarios – it is not a replacement for modeling maintenance outages with a single contingency on an adjacent facility.

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 Order 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.

Likes 0

Dislikes 0

Response

The P8 planning event was removed and made an extreme event.

The language in the standard allows the TP/PC to develop a technical rationale in order to determine the Contingencies expected to produce more severe impacts on its portion of the BES. This technical rationale can include critical stations. However, the contingency selection must include generators, transmission circuits, transformers, shunt devices and buses. Understanding the Order 754 only evaluated specific buses and had a brightline criteria. The SAMS and SPCS report was clear to expand the requirements to study more than the facilities included in the SAMS and SPCS report.

The SAMS and SPCS recommendations did not recommend a change to this list of faulted elements and the SDT feels that removing generators, transmission circuits, and transformers is not in the best interest of the reliability of the BES.

There are many instances where a disturbance followed by a breaker failure results in the exact same study as a disturbance followed by a protection failure. There could be slight differences in clearing times and the TP/PC can choose to run P4 and P5 as one study using the longest clearing time. However, in the event of a bus fault followed by a bus differential protection failure, there is a single relay communicating to several breakers which are the breakers attached to the bus. A bus fault on a breaker and a half scheme or double breaker double bus scheme are particularly problematic. In the P5 event for this type of protection failure, none of the breakers which should open to clear the fault will get the signal from the relay in order and clear the bus fault. This makes the bus differential P5 event significantly more severe than the P4 event. The FERC Order 754 Section 1600 data request was specific to bus faults followed by a single point of failure of the protection system.

In cases where a P4 analysis at a specific location will be the same as a P5 analysis. Example: failure of a control circuitry associated with a breaker trip coil results in the same analysis as the P4 for the breaker failing to open in order to clear the fault. Therefore, the P4 and the P5 is the same simulation.

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.

Likes 0

Dislikes 0

Response

The SDT agrees and P8 was removed. A three-phase fault followed by a protection failure remains an extreme event.

The SDT added clarifying language for footnote 13 to the technical rationale which follows the standard.

In IRO-017, there are outages studied in the Time Horizon: Operations Planning, but IRO-017 R4 states that the Planning Assessment for outages must be coordinated with the RC and the Time Horizon: Long-Term Planning. So there is not an overlap since the Time Horizons are different. Also, without a change to TPL-001 for studying outages, there is a gap for IRO-017 R4 requirements.

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

The SDT appreciates the comments provided by JEA and City Light. The SDT has removed the P8 event and made the three-phase fault followed by a failure of the protection system an extreme event.

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.

Likes 0

Dislikes 0

Response

The SDT has removed the P8 event and made the three-phase fault followed by a failure of the protection system an extreme event.

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

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.”

Likes 0

Dislikes 0

Response

1. Changes were made to the language related to outages along with revisions to parts 2.1.3 and 2.4.3. The TP/PC needs to have a technical rationale that identifies which outages are “significant”.

2. The station DC supply includes station battery, battery chargers and non-battery-based dc supply. This list is included in the NERC Glossary of terms under “*Protection System*”. There is a NERC Technical Paper dated November 2008 titled “*Protection System Reliability Redundancy of Protection System Elements*” which explains why monitoring an “open circuit” is required. The SAMS and SPCS recommendation from Order 754 and Section 1600 data request aligns with most of the elements in the NERC Technical Paper. For reference Figure 5-12 is copied from this technical paper.

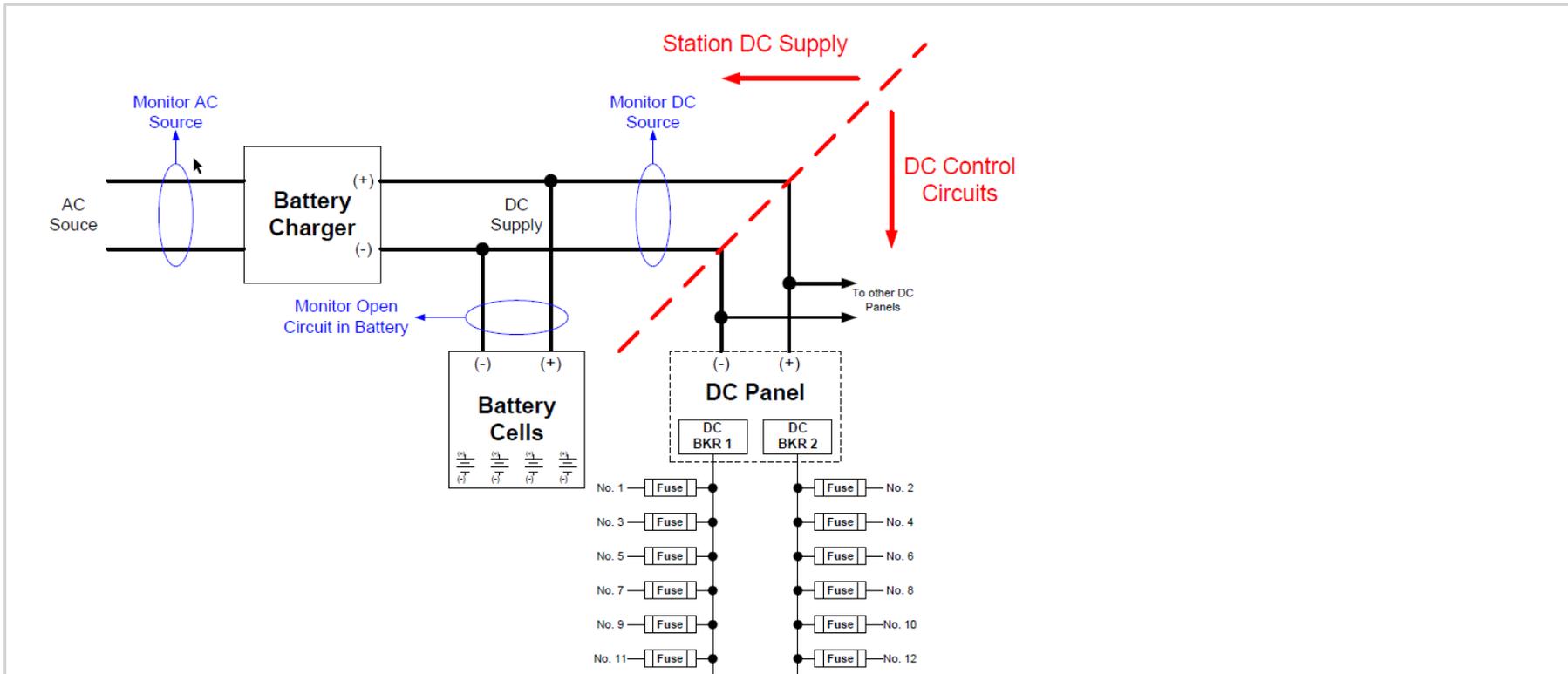


Figure 5–12 — Station DC Supply and Monitoring

For these reasons monitoring of both open circuit and low voltage are required **OR** redundant meaning two batteries, and redundant meaning two battery chargers, etc. The SDT is sympathetic to the fact that open circuit may be problematic and could introduce additional points of failure. However, the FERC directive, SAMS and SPCS Order 754 recommendations and NERC Technical Paper needs to be followed.

Richard Vine - California ISO - 2

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

The SDT removed the circular issue by removing the requirement to model “known outages” in R1 and added language to study known outages in Requirement R2, Parts 2.1.3 and 2.4.3. Other revisions to these sections should satisfy California ISO.

The SDT hopes the added language to Parts 2.1.3 and 2.4.3 addresses the California ISO concern on the language “expected to produce more severe System impacts on its portion of the BES”.

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

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

TPL-001-5 footnote 13d was revised to include monitoring of trip coils.

The SDT understands that monitoring PRC-005 results in extended maintenance periods of some protection systems. The purpose of TPL-001-5 is to give directions to the TP/PC of the elements that must be studied. The SDT does not see a direct correlation between PRC-005 and TPL-001 since a planning standard and a maintenance standard are very different.

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.
- 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.
- 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.

- 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

The SAMS and SPCS report as a result of Order 754 identified a risk to the BES for both GO and TO facilities and did not recommend a change to the list of faulted elements. Therefore, limiting the single point of failure to generation facilities is not in the best interest of the reliability of the BES.

The SDT discussed at length adding either GO and/or TO as applicable entities to ensure that CAP are actually implemented. It was determined that the SAR for this SDT does not allow this change.

Limiting TPL-001-5 to EHV only will not eliminate the risk to the BES identified in the SAMS and SPCS Order No. 754.

The SDT cannot add a timeframe for reporting communication failures to the control center since this adds a requirement to the TO or GO. The SDT does not believe they have the authority to add TO or GO as an applicable entity.

The SDT understands that implementing either monitoring or adding redundancy to DC supplies can be problematic. However, the first step is to determine in the Planning Assessment if there is a risk to the BES as a result of a single line to ground fault followed by loss of the DC supply. If there is a risk to the BES, it does not seem like this added cost to implement redundancy is high compared to the risk.

Oshani Pathirane - Oshani Pathirane On Behalf of: Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3; - Oshani Pathirane

Answer

No

Document Name	
Comment	
<p>Hydro One still has concerns with the following points regarding Footnote 13:</p> <ol style="list-style-type: none"> 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). 	
Likes	0
Dislikes	0
Response	
<p>1) There is a NERC Technical Paper dated November 2008 titled “<i>Protection System Reliability Redundancy of Protection System Elements</i>” which explains why monitoring an “open circuit” is required. The SAMS and SPCS recommendation from Order No. 754 and Section 1600 data request aligns with most of the elements in the NERC Technical Paper. For reference Figure 5-12 is copied from this technical paper.</p>	

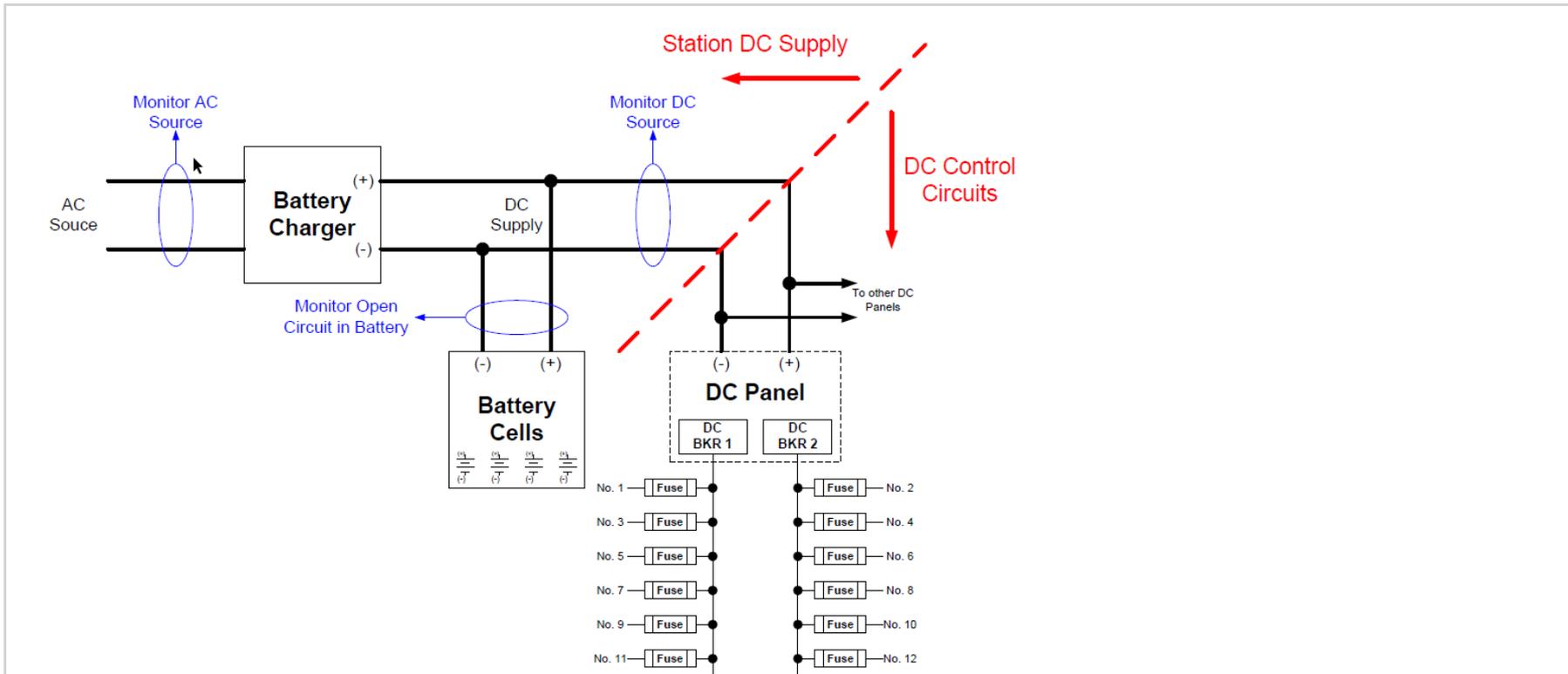


Figure 5–12 — Station DC Supply and Monitoring

2) Monitoring was added to footnote 13d.

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

The SDT appreciates the comments provided by JEA and TVA. The SDT has removed the P8 event and made the three-phase fault followed by a failure of the protection system an extreme event. All associated language was also revised.

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

Thank you for your comments. The addition of the Table 1 P8 Planning Event has been removed from the proposed TPL-001-5.

According to the FERC Order No. 786, there is no direct correlation between the time duration of an outage and system impact. A shorter duration outage may be more impactful to the system than a three-month outage. The range of industry comments reflects, in part, the substantial regional differences in outage coordination methods and procedures to address these known maintenance outages. A three-

month outage duration would ignore the basic differences in network topology, load level, and load shape of each region and entity. Outage duration can be one of the criteria, but not the only criterion. Examples of other factors to be considered are enumerated in Requirement R2, Part 2.1.3 and 2.4.3.

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 address 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 address 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 0

Dislikes 0

Response

The SDT appreciates the comments provided by MEAG Power. The SDT has removed the P8 event and made the three-phase fault followed by a failure of the protection system an extreme event. All associated language was also revised.

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:

Requiemment 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).

Likes 0

Dislikes 0

Response

- 1) The language in Requirement R2, Parts 2.1.3 and 2.4.3 has been revised in the newest red-line version of the standard.
- 2) The latest standard for parts Requirement R2, Parts 2.1.3 and 2.4.3 are significantly different than the prior posting
- 3) The SDT has removed the P8 event and made the three-phase fault followed by a failure of the protection system an extreme event.

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?

Likes 0

Dislikes 0

Response

The language in TPL-001-4 contains the following language for all P1 through P7 and extreme events “... events in Table 1, that are expected to produce more severe System impacts ...”. While your statement is true, an entity could ignore some P1 events that are more severe or most severe, changing the standard to require all P1 events will be arduous for some entities. Additionally, this changes was not included in the SAR and the SDT may not have the authority to make this change at this time. Each entity in their selection of the P1 contingencies must have a technical rationale for identifying the P1 contingencies they select. As an RE, you can make recommendations that they revise their technical rationale to include something they are not including at present.

It was the intent of the SDT to require stability to be performed on P8 events. Due to other comments P8 was removed as a planning event and kept as an extreme event.

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.

Likes 0

Dislikes 0

Response

The SDT does not have authorization in the SAR to limit the scope of dynamic simulations. The TP/PC can utilize a contingency selection criteria in the technical rationale. The list of stability analysis contingencies can include only those Contingencies where if lost results in more severe impacts to the BES. This language exists in TPL-001-4 and is not being revised by the SDT of TPL-001-5.

The FERC directive from Order No. 786 requested “significant” outages be studied with a duration time less than six months. The SDT has difficulty defining “Significant Outages” that work for all entities from the east coast to the west coast. The language “Known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure, or according to a technical rationale ...” allows the TP/PC to have a documented procedure or technical rationale which is designed to reduce the list of outages required to be studied. It is up to the TP/PC to determine what “Significant Outages” mean for their system. The language was not intended for the TP/PC to study all outages. For KCP&L, their technical rationale can state “specific areas local to the equipment” that are more critical to KCP&L’s portion of the BES.

Long Lead Equipment: TPL-001-4 requires steady state studies be performed for items Long Lead Transmission equipment that do not have spares. Adding spare equipment can reduce the need for performing stability studies for these types of equipment. FERC Order No. 786 directed the SDT to add language requiring Long – Lead Equipment without a spare be studied in stability not just steady state. Therefore, the SDT is required to make this revision to the standard.

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:

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.

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.

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.

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’.

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?

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

The spare equipment language in Requirement R2, Part 2.4 mirrors the language in the TPL-001-4 2.1.5. The SDT does not desire to revise the existing language in Requirement R2, Part 2.1.5. However, clarity on what is meant by the spare equipment strategy is being added to the technical rationale.

The SDT affirms that all parts of footnote 13 has to be either redundant, or monitored (footnote 13 b, c, and d) or studied as a P5 event. The technical rationale is used to develop a contingency list of BES facilities that if lost have a more severe impact to the BES. Once the list of BES facilities are identified all parts of footnote 13 must be evaluated as a P5 event.

The footnote 13 focuses on the components of a Protection System to be considered as having a reliability impact from Single Points of Failures.

Footnote 13a is the only part of the footnote that does not have monitoring. TPL-001-4 P5 is for non-redundant relays. If monitoring were added to footnote 13a, it lowers the bar from where TPL-001-4. There is no desire from the SDT to lower the bar.

Related to “comparable” in footnote 13a, in the context of comparable Normal Clearing, and “alternative” relay terms, additional clarity was added to the technical rationale.

The relay classified as an “alternative” relay can be considered “redundant”, if it is designed with the same performances as the protective relay such as the operating time, selectivity (tripping of the same elements).

If not, the alternative relay, which responds in a delayed clearing time and trips more elements than the protective relay, cannot be considered redundant. Then the P5 event will need to be studied using the delayed clearing time. Any elements expected to be tripped by the alternative relay must be tripped during the P5 simulation.

DC control circuitry includes everything from where the DC supply ends up to and including the trip coils. This includes the wires, auxiliary relays and lockout relays. We agree with the suggestion that additional clarity should be added to the technical rationale.

According to the NERC State of Reliability 2014 report, the top causes of failure are: incorrect setting, logic, or design error, relay failures/malfunctions. Relays have higher rate of failure compared to station dc supply and communication system.

Therefore, the protection system design must consider the protective relays exposure to higher risk of failure.

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).

Likes 0

Dislikes 0

Response

Revisions to Requirement R3, Parts 3.2 and 3.5: This is a good suggestion the standard was revised with this change.

Revisions to Requirement R4, Part 4.1.1 through 4.1.3: This is also a good suggestion. However, the issue is contained in TPL-001-4. The SDT also feels that adding additional columns to Table 1 will make it very difficult to see on standard printable paper.

Related to Requirement R2, Part 2.7: If Table 1 does NOT allow non-consequential load loss and/or interruption of Firm Transmission Service and footnote 12 does not apply, a TP/PC can utilize Part 2.7.3 until a CAP can be implemented.

If the non-consequential load loss or interruption of Firm Transmission Service can be done in order to meet the performance requirements and it is allowed in Table 1, then the CAP is required but it could be an operating procedure which identifies the load to drop or transmission service to curtail in order to meet the performance requirements. The NERC Glossary for a CAP can include operations instructions or specific construction of projects.

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.

Likes	0	
Dislikes	0	
Response		

Footnote 13b: The SDT agrees that monitoring does not provide the same robustness as redundancy. However, the SDT is going above the exact recommendation of the SAMS and SPCS report when communications were added to footnote 13. So monitoring was also added since monitoring is allowed for footnote 13 c and d.

The SDT agrees that not all communication failures result in delayed clearing and therefore these would not need to be studied.

The TP/PC is allowed to identify a critical clearing time and that can be given to the protection engineer to ensure that all parts of footnote 13 are meeting at least this critical clearing time. However, the SDT does not want to be so prescriptive in identifying exactly how the TP/PC should run the P5 analyses.

Footnote 13c: Based on comments from industry monitoring of open circuit is not common and can be problematic, but the SDT does not desire to change the requirement. Redundancy of batteries and chargers is a second option if the performance requirements are not met, adding redundancy being the primary option. A NERC Technical Paper dated November 2008 titled *“Protection System Reliability Redundancy of Protection System Elements”*. This document explains why monitoring an “open circuit” is required. The following diagram was taken from the referenced document.

Per the FERC Order No. 754 and SAMS/SPCS report from the Section 1600 data request, the SDT believes that the changes to this standard IS the appropriate place FERC has decided to drive the requirement to retrofit existing installations with open circuit monitoring or install redundant DC supplies, in spite of the low probability of failure.

The SDT understands that GREs substations below 200 kV may be impacted by the changes to this standard. However, there is also a lower probability that there exists performance requirement violations at these lower voltage classes.

The SDT does not feel they have the authority to address PRC-005 requirements.

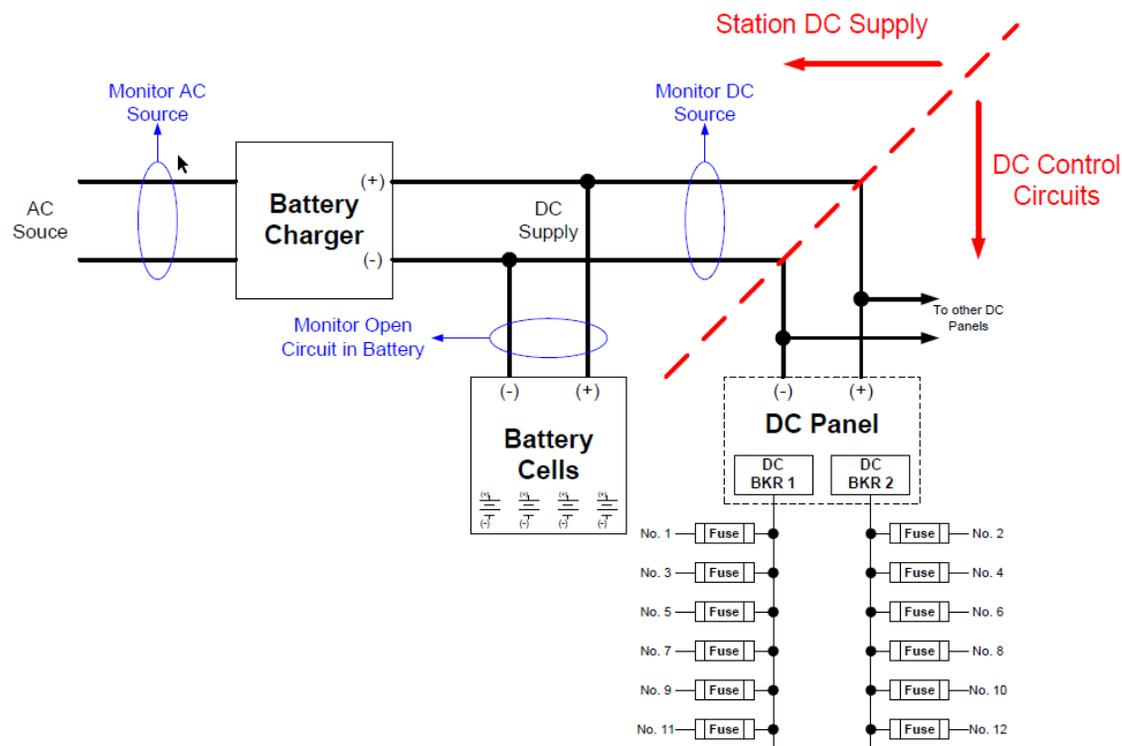


Figure 5–12 — Station DC Supply and Monitoring

The protection experts that the SDT consulted with state that monitoring for “open circuit” can be done without adding to the probability of failure.

Footnote 13d.

- It is correct, the DC control circuitry includes trip coils, auxiliary relays and wires. Footnote 13d applies to everything piece of equipment where the DC supply stops up to and including the trip coils.
- The protection group should be able to identify whether there are single control circuitry.

- For evidence a written notification from the Protection Engineer to the Planning Engineer of which portions of the protection system are or are not redundant. The Planning Engineer via the “technical rationale” can determine what facilities if lost would result in more severe impacts to the BES. The SDT suggests listing the four components of footnote 13 for every location identified by the technical rationale, then the Protection Engineer must look at the protection system at each of these Facilities and identify which have redundancy and give this information back to the Planning Engineer along with the clearing times required to perform the appropriate studies. If redundancy does not exist, then the Planning Engineer needs to perform the studies and determine where redundancy must be added or identify other forms of CAPs.
- Monitoring was added to footnote 13d which is intended to make the requirements easier to comply with.

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

Answer	No
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	
The SDT agrees with this suggestion and revision was made.	
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

Requirement R2, Parts 2.1.3 and 2.4.3: The language of these two parts were significantly revised.

Footnote 13b

While most people may agree with this comment that monitoring of communications is not sufficient, the SDT went above and beyond the SAMS and SPCS recommendations when they added communication-aided protection scheme to footnote 13. The SDT intentionally did not include interval and reporting since it looked like this would add “Transmission Owner” as a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP.

Footnote 13c

The technical rationale which accompanies the standard will include wording that the single DC supply includes batteries and chargers. The SDT intentionally did not include interval and reporting since it looked like this would require “Transmission Owner” be a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP and put responsibility of monitoring on the incorrect entity.

Footnote 13d

While a risk based approach which may eliminate the wires is a good suggestion, the control circuitry includes trip coils, auxiliary relays and wires. Footnote 13 d applies to every piece of equipment where the DC supply stops up to and including the trip coils. In order to make DC Control Circuitry, monitoring of DC control circuitry was added to footnote 13d.

Footnote 14: The P8 planning event was removed and a three-phase fault was made an extreme event, so we believe this comment no longer applies.

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.	
Likes 0	

Dislikes 0

Response

The SDT does not want to list all the elements included in the “single station dc supply”. As a minimum it includes the station battery, battery charger and non-battery-based dc supply as defined in the NERC Glossary under “Protection System”. A battery charger may not have enough power to open several breakers for a bus differential and causing a protection system not to function if the battery itself fails. The diagram below from NERC Technical Paper dated November 2008 titled “Protection System Reliability Redundancy of Protection System Elements” shows how monitoring for both open circuit and low voltage should be done.

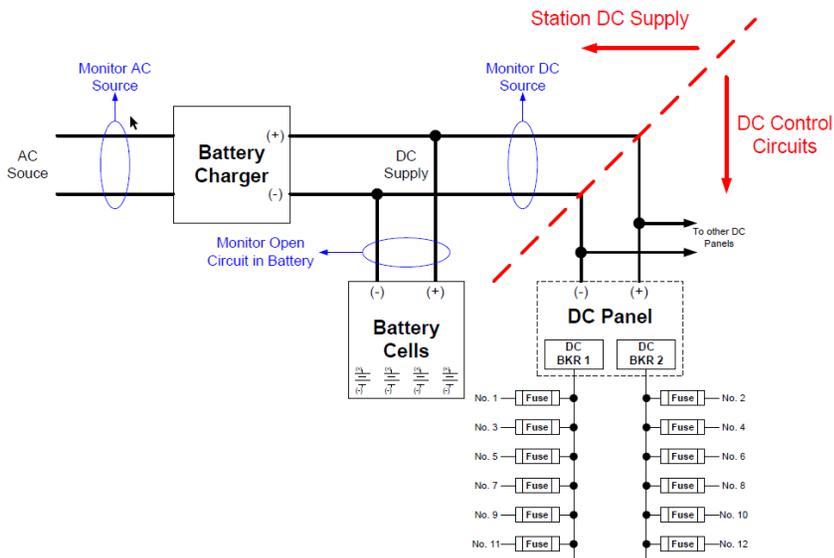


Figure 5-12 — Station DC Supply and Monitoring

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

Answer

No

Document Name	
Comment	
<p>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.”</p> <p>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.</p> <p>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”.</p> <p>Same explanatory text as Part 2.1.3.</p> <p>Table 13, Footnote 13</p> <p>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.</p> <p>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.</p> <p>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</p>	

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. “

Likes 0

Dislikes 0

Response

Requirement R2, Part 2.1.3 and 2.4.3: The language of these two parts were significantly revised.

Footnote 13b

While most people may agree with this comment that monitoring of communications is not sufficient, the SDT went above and beyond the SAMS and SPCS recommendations when they added communication-aided protection scheme to footnote 13. The SDT intentionally did not include interval and reporting since it looked like this would add “Transmission Owner” as a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP.

In case of single points of failure in the communication system associated with the protective functions causing their failure to operate, the system performances can be preserved by an adequate design that involves the communication system and the backup protection. However, single points of failure of a protective relay will result in delayed fault clearing. Moreover, the failure may remain undetected until the relay is tested, depending on the relay type (electromechanical relay, microprocessor relay) and protection system design. According to the NERC State of Reliability 2014 report, the top causes of failure are: incorrect setting, logic, or design error, relay failures/malfunctions. Relays have higher rate of failure compared to station dc supply and communication system.

Footnote 13c

The technical rationale which accompanies the standard will include wording that the single DC supply includes batteries and chargers. The SDT intentionally did not include interval and reporting since it looked like this would require “Transmission Owner” be a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP and put responsibility of monitoring on the incorrect entity.

Footnote 13d

While a risk based approach which may eliminate the wires is a good suggestion, the control circuitry includes trip coils, auxiliary relays and wires. Footnote 13d applies to every piece of equipment where the DC supply stops up to and including the trip coils. In order to make DC Control Circuitry, monitoring of DC control circuitry was added to footnote 13d.

Footnote 14: The P8 planning event was removed and a three-phase fault was made an extreme event, so we believe this comment no longer applies

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

Thank you for your comment. The SDT believes the language in the FERC Order No. 786 was clear and the requirement to have stability analysis performed for P1 and P2 was part of the FERC Order. The P3-P7 planning events have a lower probability of occurrence and this is likely the reason that they were not included in FERC Order No. 786.

John Bee - Exelon - 3

Answer

No

Document Name

Comment

See Exelon TO Utilities Comments

Likes 0

Dislikes 0

Response

SDT appreciates your comments. The implementation plan has been revised and clarified based upon the comments received from the industry and removal of the P8 categories from the planning events. To further clarify the implementation plan, SDT has also added a diagram showing the timeline.

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

Answer

No

Document Name

Comment	
See response to questions 1 and 2.	
Likes	0
Dislikes	0
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
<p>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.</p> <p>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.</p> <p>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.</p> <p>Same explanatory text as Part 2.1.3.</p> <p>Table 1, Footnote 13</p>	

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. “

Likes 0

Dislikes 0

Response

Requirement R2, Parts 2.1.3 and 2.4.3: The language of these two parts were significantly revised.

Footnote 13b

While most people may agree with this comment that monitoring of communications is not sufficient, the SDT went above and beyond the SAMS and SPCS recommendations when they added communication-aided protection scheme to footnote 13. The SDT intentionally did not include interval and reporting since it looked like this would add “Transmission Owner” as a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP.

In case of single points of failure in the communication system associated with the protective functions causing their failure to operate, the system performances can be preserved by an adequate design that involves the communication system and the backup protection. However, single points of failure of a protective relay will result in delayed fault clearing. Moreover, the failure may remain undetected until the relay is tested, depending on the relay type (electromechanical relay, microprocessor relay) and protection system design. According to the NERC State of Reliability 2014 report, the top causes of failure are: incorrect setting, logic, or design error, relay failures/malfunctions. Relays have higher rate of failure compared to station dc supply and communication system.

Footnote 13c

The technical rationale which accompanies the standard will include wording that the single DC supply includes batteries and chargers. The SDT intentionally did not include interval and reporting since it looked like this would require “Transmission Owner” be a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP and put responsibility of monitoring on the incorrect entity.

Footnote 13d

While a risk based approach which may eliminate the wires is a good suggestion, the control circuitry includes trip coils, auxiliary relays and wires. Footnote 13d applies to every piece of equipment where the DC supply stops up to and including the trip coils. In order to make DC Control Circuitry, monitoring of DC control circuitry was added to footnote 13d.

Footnote 14: The P8 planning event was removed and a three-phase fault was made an extreme event, so we believe this comment no longer applies.

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.	
Likes 0	
Dislikes 0	
Response	
The language in Requirement R1, Part 1.1.2.2 was revised. The SDT agrees and have removed P8 and made three phase faults an extreme event.	
Ellen Oswald - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
<p>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.”</p> <p>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.</p> <p>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”.</p> <p>Same explanatory text as Part 2.1.3.</p>	

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. “

Likes 0

Dislikes 0

Response

Requirement R2, Parts 2.1.3 and 2.4.3: The language of these two parts were significantly revised.

Footnote 13b

While most people may agree with this comment that monitoring of communications is not sufficient, the SDT went above and beyond the SAMS and SPCS recommendations when they added communication-aided protection scheme to footnote 13. The SDT intentionally did not include interval and reporting since it looked like this would add “Transmission Owner” as a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP.

In case of single points of failure in the communication system associated with the protective functions causing their failure to operate, the system performances can be preserved by an adequate design that involves the communication system and the backup protection. However, single points of failure of a protective relay will result in delayed fault clearing. Moreover, the failure may remain undetected until the relay is tested, depending on the relay type (electromechanical relay, microprocessor relay) and protection system design. According to the NERC State of Reliability 2014 report, the top causes of failure are: incorrect setting, logic, or design error, relay failures/malfunctions. Relays have higher rate of failure compared to station dc supply and communication system.

Footnote 13c

The technical rationale which accompanies the standard will include wording that the single DC supply includes batteries and chargers. The SDT intentionally did not include interval and reporting since it looked like this would require “Transmission Owner” be a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP and put responsibility of monitoring on the incorrect entity.

Footnote 13d

While a risk based approach which may eliminate the wires is a good suggestion, the control circuitry includes trip coils, auxiliary relays and wires. Footnote 13 d applies to every piece of equipment where the DC supply stops up to and including the trip coils. In order to make DC Control Circuitry, monitoring of DC control circuitry was added to footnote 13 d.

Footnote 14: The P8 planning event was removed and a three-phase fault was made an extreme event, so we believe this comment no longer applies.

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

Answer	No
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Document Name	
Comment	
MEC supports NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Requirement R2, Parts 2.1.3 and 2.4.3: The language of these two parts were significantly revised.	
<p>Footnote 13b</p> <p>While most people may agree with this comment that monitoring of communications is not sufficient, the SDT went above and beyond the SAMS and SPCS recommendations when they added communication-aided protection scheme to footnote 13. The SDT intentionally did not include interval and reporting since it looked like this would add “Transmission Owner” as a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP.</p> <p>In case of single points of failure in the communication system associated with the protective functions causing their failure to operate, the system performances can be preserved by an adequate design that involves the communication system and the backup protection. However, single points of failure of a protective relay will result in delayed fault clearing. Moreover, the failure may remain undetected until the relay is tested, depending on the relay type (electromechanical relay, microprocessor relay) and protection system design. According to the NERC State of Reliability 2014 report, the top causes of failure are: incorrect setting, logic, or design error, relay failures/malfunions. Relays have higher rate of failure compared to station dc supply and communication system.</p> <p>Footnote 13c</p> <p>The technical rationale which accompanies the standard will include wording that the single DC supply includes batteries and chargers. The SDT intentionally did not include interval and reporting since it looked like this would require “Transmission Owner” be a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP and put responsibility of monitoring on the incorrect entity.</p>	

Footnote 13d

While a risk based approach which may eliminate the wires is a good suggestion, the control circuitry includes trip coils, auxiliary relays and wires. Footnote 13d applies to every piece of equipment where the DC supply stops up to and including the trip coils. In order to make DC control circuitry, monitoring of DC control circuitry was added to footnote 13d.

Footnote 14: The P8 planning event was removed and a three-phase fault was made an extreme event, so we believe this comment no longer applies

Dennis Sismaet - Northern California Power Agency - 6

Answer	No
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Document Name	
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Comment

Please see JEA's comments.

Likes	0
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Dislikes	0
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Response

The SDT appreciates the comments provided by JEA and Northern California Power Agency. The SDT agrees and has removed the P8 event and made the three-phase fault followed by a failure of the protection system an extreme event. All associated language was also revised.

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

Answer	No
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Document Name	
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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 and R4.5 to maintain consistency.

Likes	0
Dislikes	0

Response

Table 1, Footnote 13d

The TP/PC needs to perform studies and then develop CAPs. The SDT agrees that many parts of P5 footnote 13 and with P4 events results in the same study and therefore the same results. However, if the performance requirements are not met, the CAP needs to cover the P4

stuck breaker issue, and any of the P5 things that are not redundant and/or monitored. Therefore the study of a single planning event may be the same for P4 and many parts of a P5 and it only has to be studied once. However, if this study identifies performance requirement violations, the CAP can be very different. An example of a CAP could be: add stuck breaker scheme to the protection system, add a redundant relay, add redundant control circuitry, add monitoring of DC power supply for both open circuit and low voltage, add monitoring of communication-aided protection scheme. All these things could be required to mitigate the issue identified in the single simulation of the planning assessment. A CAP which eliminates just the stuck breaker issue is not good enough. All components of the protection system listed in footnote 13 have to be included in the CAP along with a method of mitigating the stuck breaker performance violation when a P4 has the same clearing time as the P5. All components of the protection system as well as breakers have to be listed in the standard so as not to eliminate portions of the CAP that would be required in the event that a performance requirement violation shows up in the planning assessment. The P4 and P5 components are not listed to identify both what needs to be studied is also intended to ensure that the CAP includes all the necessary items to improve the reliability of the BES.

The SDT is not attempting to list all things which are included in Footnote 13d since there is likely equipment that exists somewhere that will not be on the list. Footnote 13d includes all things between where the DC supply ends up to and including the trip coils, which includes auxiliary and lockout relays, wires everything from a specific point to another specific point.

Footnote 13c:

This is a very good comment and was considered. Since the SDT cannot come up with an exhaustive list that incorporates all things that can exist in the electric grid from the east coast to the west coast, additional language was added to the technical rationale which follows the standard and should be referred when an entity is unclear what is meant by “Single Station DC supply”.

Requirement R4, Parts 4.2 and 4.5:

The SDT agrees with this comment and made the change to the standard.

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

Answer	No
Document Name	
Comment	

LADWP doesn't agree with the new proposed revisions specifically the new planning event P8 and the changes made to R4.

Likes 0

Dislikes 0

Response

The SDT agrees and P8 was removed along with adding a 3-phase fault followed by a protection failure is an extreme event.

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

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.

Likes 0

Dislikes 0

Response

Footnote 13d:

Monitoring was added to footnote 13d.

Extreme Event:

The SDT Agrees with this comment and appropriate changes were made.

Quintin Lee - Eversource Energy - 1, Group Name Eversource Group**Answer**

No

Document Name**Comment**

See Question 2 response

Likes 0

Dislikes 0

Response

Thank you for your comment.

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

No

Document Name**Comment**

See JEAs response.

Likes 0

Dislikes 0

Response

The SDT appreciates the comments provided by JEA and Northern California power Agency. The SDT agrees and has removed the P8 event and made the three-phase fault followed by a failure of the protection system an extreme event. All associated language was also revised.

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

Thank you for your comment.

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. “

Likes	0
Dislikes	0
Response	

Requirement R2, Parts 2.1.3 and 2.4.3 are significantly revised.

Footnote 13b: TPL-001-4 P5 is applicable to non-redundant relays and does not allow for monitoring. The SDT does not want to reduce the bar from TPL-001-4 by adding monitoring.

Footnote 13c: The technical rationale contains language clarifying what footnote 13c includes. If interval of monitoring were included, the TO would have to be an applicable entity in the standard. This would go against the SAR.

Footnote 13d: The technical rationale includes additional language on what is defined as DC control circuitry. While the SDT agrees that wires have a lower risk of failure, wires are part of the DC control circuitry. In the latest version of the red-line version of the standard, monitoring of footnote 13d was added. Hopefully, this change is more palatable.

Footnote 13b

While most people may agree with this comment that monitoring of communications is not sufficient, the SDT went above and beyond the SAMS and SPCS recommendations when they added communication-aided protection scheme to footnote 13. The SDT intentionally did not include interval and reporting since it looked like this would add “Transmission Owner” as a functional entity to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP.

In case of single points of failure in the communication system associated with the protective functions causing their failure to operate, the system performances can be preserved by an adequate design that involves the communication system and the backup protection. However, single points of failure of a protective relay will result in delayed fault clearing. Moreover, the failure may remain undetected until the relay is tested, depending on the relay type (electromechanical relay, microprocessor relay) and protection system design. According to the NERC State of Reliability 2014 report, the top causes of failure are: incorrect setting, logic, or design error, relay failures/malfunions. Relays have higher rate of failure compared to station dc supply and communication system.

Footnote 13c

The technical rationale which accompanies the standard will include wording that the single DC supply includes batteries and chargers. The SDT intentionally did not include interval and reporting since it looked like this would add “Transmission Owner” as a functional entity

to the standard. Since the TP and PC do not have direct control over monitoring intervals and reporting times it was felt that evidence of intervals and reporting could not be easily obtained by a PC/TP.

Footnote 13d

While a risk based approach which may eliminate the wires is a good suggestion, the control circuitry includes trip coils, auxiliary relays and wires. Footnote 13 d applies to everything piece of equipment where the DC supply stops up to and including the trip coils. FERC directive was to implement the SAMS and SPCS recommendations from Order 754 and section 1600 data request. According to the SAMS and SPCS recommendation from Order 754 and Section 1600 data request and NERC Technical Paper dated November 2008 titled “Protection System Reliability Redundancy of Protection System Elements”, wiring of the DC controls needs to be included as redundant. The SAMS and SPCS recommendation was in the FERC order requesting changes to TPL-001-4.

Footnote 14: In the latest version of the standard, the P8 event was removed and a three-phase fault followed by a protection failure was made an extreme event.

Shawn Abrams - Santee Cooper - 1

Answer	No
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Document Name	
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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.

Likes 0	
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Dislikes 0	
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Response

The SDT is following the FERC orders for the revisions recommended. CAPs can include operating guides which are little or no cost. Without more specifics on this comments, the SDT is not able to respond with any more detail.

Patricia Robertson - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
<p><i>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.</i></p> <p><i>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.</i></p> <p><i>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.</i></p>	
Likes	0
Dislikes	0
Response	

The SDT appreciates this comment. The SDT believes that they are following the FERC directive in making the revised P5 applicable to EHV and HV protection systems. TPL-001-4 P5 applicable to non-redundant relay is currently applicable to both EHV and HV. The SDT believes the implementation plan allows for the time it will take including the time to identify the CAPs required.

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

Answer No

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.

Likes 0

Dislikes	0
Response	
<p>Requirement R2, Parts 2.1.3 and 2.4.3: This language was revised substantially.</p> <p>Part 2.4.3: The use of a technical rationale to determine the “significant outages” which must be studied is already in the standard. There is nothing in the language that prevents LES, from running a separate set of “significant outage” on stability compared to steady state as long as this is documented in the technical rationale.</p> <p>Footnote 13a: The SDT has made a clarification about what a comparable clearing time represent for purposes of footnote 13 in Section 4 of the technical rationale.</p> <p>Footnote 13c: The SDT believes that an open circuit on the DC supply will cause a protection failure so both open circuit and low voltage must be monitored OR redundant battery and charger is required if performance requirements of the study are not met. The SDT believes that in some cases like in bus differential protections, the charging system will not have enough current to send a signal to all the trip coils that must be activated. Therefore, the charging system is not sufficient backup for the DC supply. TPL-001 is a standard for identifying studies required in order to plan the system. PRC-005 is a maintenance standard for identifying the maintenance periods. There is no correlation to these two standards.</p>	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
<p>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</p>	

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.

Likes	0
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Dislikes	0
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Response

The P8 event was removed and a three phase fault remains an extreme event.

Additional clarification has been made in the technical rationale around the word “comparable”.

Footnote 13b and 13c have been modified and a language was added to the technical rationale to clarify what was meant with monitored and reported to a control center.

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

Answer	No
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Document Name	
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Comment	
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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

The SDT appreciates these comments. The answers to your questions are very lengthy for inclusion in this response. There are many added details the SDT put into the technical rationale which follows this standard. There are many times when a P4 and P5 are the same study, however the CAP will need to include mitigations for both the P4 and P5 so both requirements had to be listed in the standard for the reliability improvements that are necessary. There are also times when a P4 and P5 are different. A bus differential protection system is one example where a P4 and P5 result in different studies. Please refer to the technical rationale all answers to your comments. If you still have questions, contact the NERC staff and more language can be added to the technical rationale in order to make it clearer.

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

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.

Likes 0

Dislikes 0

Response

The SDT appreciates the CHPD comments and agrees. The P8 planning event was removed and a three-phase fault followed by a protection failure remains an extreme event.

Footnote 13 :

13a: Single point of failure of a protective relay will result in delayed fault clearing. Moreover, the failure may remain undetected until the relay is tested, depending on the relay type (electromechanical relay, microprocessor relay) and protection system design. According to the NERC State of Reliability 2014 report, the top causes of failure are: incorrect setting, logic, or design error, relay failures/malfunctions. Relays have higher rate of failure compared to station dc supply and communication system.

13d: The footnote 13d has been modified, and a single trip coil that is both monitored and reported at a Control Center shall not be considered non-redundant.

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 address 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

The SDT appreciates the comments provided by JEA and PRPA. The SDT agrees and has removed the P8 event and made the three-phase fault followed by a failure of the protection system an extreme event. All associated language was also revised.

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

Answer

No

Document Name	
Comment	
<p>Tri-State does not agree with the language of Footnote 13:</p> <p>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.</p> <p>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.</p>	
Likes	0
Dislikes	0
Response	
<p>For P5: The first step is the TP/PC must identify a list of Facilities to be studied per the technical rationale. Then in determining the delayed clearing time for completing the studies, components of footnote 13 must be considered. The components with the longest clearing time should be identified to be able to adequately perform the stability portion. When the stability portion is complete, if there are no performance requirement violations then that portion of stability is complete, no CAP is required. If however the performance requirements are not met, then the TP/PC must identify the critical clearing time where the stability analysis meets the performance requirements. All components of footnote 13 that result in a delayed clearing time longer than the critical clearing time must be considered when identifying a CAP. For example, if a failure of a relay and trip coil both result in a delayed clearing time greater than the critical clearing time, a redundant relay AND redundant trip coil will be required in the CAP. Adding a redundant relay alone is not good enough in this example. Since language in the actual standard cannot include many of the details, some details of how to complete the assessment for P5 was put into the technical rationale. The SDT appreciates these comments concerning footnote 13. The SDT has difficulty creating an exhaustive list of exactly what components of a protection system should be included. It is likely that something would get missed when this list would need to apply to all existing protection systems from the east coast to the west coast. The SDT utilized NERC Technical Paper dated November 2008 titled <i>“Protection System Reliability Redundancy of Protection System Elements”</i></p>	

which does a better job of defining all the equipment that must be redundant. Language was added to the Technical Rationale which follows the standard. Entities should utilize the technical rationale when developing the portions of a protection system that must be redundant when performance requirements are not met as a result of the study.

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.

Likes 0

Dislikes 0

Response

The SDT does not feel that a time period for outage duration should be used as a means of identifying “significant outages”. The SDT believes that a study or test should be used to identify significant outages.

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

The P8 was removed and the three-phase fault remains an extreme event. The language in Requirement R1, Part 1.1.2 has been revised(deleted) in the proposed draft and we are hoping this is more acceptable to BPA.

John Seelke - LS Power Transmission, LLC - 1

Answer No

Document Name

Comment

See thw response to Q2.

Likes 0

Dislikes 0

Response

Thank you for your comment.

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

Thank you for your comment. The SDT cannot respond to this comment without something more specific to the comment.

Joe McClung - JEA - 3,5 - FRCC, Group Name JEA Voters

Answer	No
Document Name	
Comment	
<p>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).</p> <p>The replacement of the retired standards MOD-010 and MOD-012 with MOD-032 is appropriate.</p> <p>The inclusion of measures (M) for each Requirement is appropriate.</p> <p>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.</p> <p>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.</p> <p>The replacement of the ‘Special Protection Systems’ with ‘Remedial Action Schemes’ is appropriate.</p> <p>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.</p> <p>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.</p> <p>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</p>	

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

The SDT appreciates the comments provided by JEA. The SDT agrees and has removed the P8 event and made the three-phase fault followed by a failure of the protection system an extreme event. All associated language was also revised.

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.

Planned outages are considered in Operational Planning Assessments. **The 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

IRO-017 R4 requires coordination of the RC and TP/PC related to outages in “Time Horizon: Long-term Planning”, while the Operations Planning is in the “Time-Horizon: Operations Planning”. The SDT does not feel that there is an overlap due to the “Time Horizon” as written in IRO-017. Due to FERC Order No. 786, outage duration alone should not be used to determine significant outages. The SDT feels that a test or study should be used to determine significant outages. This test or study should be documented in a technical rationale. Similarly, TOP-003 operational studies are performed in the Operations Planning Time Horizon. So without TPL-001-5, at present the SDT believes there is a gap in being able to complete the requirements of IRO-017 Requirement R4. The FERC Order No. 786 required the language in TPL-001-4 Requirement R1 be revised to include outages with a shorter duration than six months. The test or study documented in the technical rationale can be used to identify a smaller list of “Significant Outages” to make this manageable.

The TP/PC has a list of projects required as a result of the planning assessment in the Near-Term Transmission Planning Horizon. The TO should know what outages are required in order to build the projects that the TP/PC identified in the planning assessment. A MOD-032 data request can be used by the PC to identify the lists of outages that could occur in the Near-Term Transmission Planning Horizon.

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	
<p>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.</p> <p>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 qualification in either 13.a or 13.b.</p>	
Likes	0
Dislikes	0
Response	
<p>Footnote 13 is not attempting to define what a redundant protection system is for other NERC standards. Footnote 13 is only for TPL-001-5 assessments. In Footnote 13 a risk based approach was considered and consisted to classify the component with higher/ lower risk of reliability impact from Single Points of Failures as mentioned in Footnote 13a to 13d.</p> <p>Even if monitoring is not equal to redundancy, for lower risk of reliability impact components (based on NERC 2014 analysis), the monitoring is considered sufficient and will allow excluding the associated components from P5 event study.</p> <p>TPL-001-4 P5 event is applicable to non-redundant relays and does not allow for monitoring. The SDT does not want to reduce the bar from TPL-001-4 by adding monitoring. A single point of failure of a protective relay will result in delayed fault clearing. Moreover, the failure may remain undetected until the relay is tested, depending on the relay type (electromechanical relay, microprocessor relay) and protection system design.</p>	

According to the NERC State of Reliability 2014 report, the top causes of failure are: incorrect setting, logic, or design error, relay failures/malfunctions. Relays have higher rate of failure compared to station dc supply and communication system.

Therefore, the protection system design must consider the protective relays exposure to higher risk of failure.

Thank you for this comment.

Nicolas Turcotte - Hydro-Québec TransEnergie - 1

Answer	Yes
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Document Name	
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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	
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Dislikes 0	
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Response

These issues exist in TPL-001-4 and the SDT does not feel that they have the authority to fix the items in the prior standard that was not included in the SAR.

John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson

Answer	Yes
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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	
Thanks for this comment. This has been addressed and corrected.	
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	
Due to industry comments, P8 was removed and the three-phase fault followed by a protection failure will be in extreme event. Changes were made to Requirement 1 related to known outages. IRO-017 Requirement R4 requires coordination of the RC and TP/PC related to outages in “Time Horizon: Long-term Planning”, while the Operations Planning is in the “Time-Horizon: Operations Planning”. The SDT does not feel that there is an overlap due to the “Time Horizon” as written in IRO-017. Due to FERC Order No. 786, outage duration alone	

should not be used to determine significant outages. The SDT feels that a test or study should be used to determine significant outages. This test or study should be documented in a technical rationale.

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

The known outages in Requirement 1 was removed, but studies related to known outages was revised.

Related to Table 1 Stability Extreme Event comment: This may have been an oversight from the SDT for TPL-001-4. However, the SAR does not allow the SDT of TPL-001-5 to correct potential issues of TPL-001-4.

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.

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.

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

1. The SDT cannot and should not comment on PRC-005.
2. The control circuitry begins where the DC supply ends. There are diagrams that may be helpful contained in the technical rationale.

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

The known outages in Requirement R1, Part 1.1.2 was removed, but studies related to known outages was revised.

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	
<p>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).</p> <p>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</p>	

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

The SDT removed the P8 event and a three phase fault followed by a protection failure remains an extreme event. The SDT feels that the suggested language changes to Table 1 appear to make less clarity instead of adding clarity.

The SDT added a significant amount of clarity in the technical rationale for what is redundant and what is not redundant for purposes of TPL-001-5 only.

The SDT members are not sure what is meant in this comment by the simultaneous failure of all non-redundant components of a protection system. The TP/PC can consider the components one at a time and this potentially means four simulations. Or the TP/PC could consider studying the worse delayed clearing time and discuss with the protection group which parts of footnote 13 cause performance criteria violations. The task is to determine which components of Table 1 footnote 13 are redundant (meaning backups have the same clearing time) or are monitored. If monitored or redundant for footnote 13b, c and d and redundant for footnote 13a, then no P5 stability simulations are required at this location. If they are required for simulation (not redundant and not monitored), then a determination of whether it meets performance requirements is done. If performance requirements are not met, then the CAP could be four things: Example of the four things in the CAP at the same location could be redundant relay, redundant DC control circuitry, redundant DC supply and redundant communications.

The addition of communication systems was discussed extensively and while it is true, the SAMS and SPCS report did not include this particular recommendation, the SAMS and SPCS report did contain a potential risk. The SDT attempted to minimize the impact of adding communications by also allowing it to be monitored or redundant.

The SDT made changes to Requirement R2, Parts 2.1.4, 2.4.4, Requirement R3, Part 3.5 and Requirement R4, Part 4.2 which we feel satisfies your comments to this portion.

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

Thank you for your comment.

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.

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

Thank you for your comment; The SDT has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1.

The SDT has also revised and made additional clarification to the implementation plan (CAPs for such P5 events). Industry stakeholders will have the opportunity to re-evaluate cost effectiveness of these changes in the next posting.

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

Thank you for your comment. The SDT understands the significant work introduced by the TPL-001-5 changes and has allowed sufficient lead time to complete the work as outlined in the Implementation plan.

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

Thank you for your comment. Consistent with the intention of FERC Order No. 786, the SDT included the specification of known outages to be modeled based on the accompanying factors outlined in the TPL-001-5. Industry stakeholders will have the opportunity to re-evaluate cost effectiveness of the changes in the next posting.

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

Thank you for your comment. Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. Consistent with the intention of FERC Order No. 786, the SDT included the specification of known outages to be modeled based on the accompanying factors outlined in the TPL-001-5. Industry stakeholders will have the opportunity to re-evaluate cost effectiveness of the changes in the next posting.

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

Thank you for your comment; Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. Consistent with the intention of FERC Order No. 786, the SDT included the specification of known

outages to be modeled based on the accompanying factors outlined in the TPL-001-5. The SDT has added language to Footnote 13 for clarity and also the technical rationale provides additional details related to your comments. Industry stakeholders will have the opportunity to re-evaluate cost effectiveness of the changes in the next posting.

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

Thank you for your comment. The SDT has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1.

The SDT has also revised and made additional clarification to the implementation plan (CAPs for such P5 events). Industry stakeholders will have the opportunity to re-evaluate cost effectiveness of these changes in the next posting.

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

Thank you for your comment. The SDT has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1.

The SDT has also revised and made additional clarification to the implementation plan (CAPs for such P5 events). Industry stakeholders will have the opportunity to re-evaluate cost effectiveness of these changes in the next posting.

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

The SDT appreciates these comments. Please refer to the SDT response to your question 4 and also the technical rationale provides additional details related to your comments.

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

Thank you for your comment. The SDT is addressing directives as ordered by FERC for the revisions recommended. CAPs can include operating guides which are little or no cost. Without more specifics on this comments, the SDT is not able to respond with any more detail.

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.

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

Thank you for your comment; The SDT has added language to Footnote 13d for clarity and also the updated technical rationale provides additional details. The SDT has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1 and. Industry stakeholders will have the opportunity to re-evaluate cost effectiveness in the next posting.

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

Thank you for your comment. Please refer to the SDT's response to JEA comments.

Marty Hostler - Northern California Power Agency - 5

Answer

No

Document Name

Comment

See JEAs response.	
Likes	0
Dislikes	0
Response	
Thank you for your comment. Please refer to the SDT’s response to JEA comments.	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	No
Document Name	
Comment	
<p>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 occurrences in the industry, requiring a CAP is not an 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”. <i>See Order 754 Assessment at p. 11.</i></p>	
Likes	0
Dislikes	0
Response	
Thank you for your comment. The SDT is addressing directives as ordered by FERC for the revisions recommended. The SDT has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1. The SDT has also revised and made additional clarification to the implementation plan (CAPs for such P5 events).	

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. Until the new proposed is agreed and approved, it would be hard to made a comment on this question.	
Likes 0	
Dislikes 0	
Response	
The SDT is addressing directives as ordered by FERC for the revisions recommended. Without more specifics on this comments, the SDT is not able to respond with any more detail.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
Please see JEA's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please refer to the SDT's response to JEA comments.	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
<p>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.</p>	
Likes 0	
Dislikes 0	
Response	
<p>Thank you for your comment. The SDT is addressing directives as ordered by FERC for the revisions recommended. The SDT understands the significant work that would be required to investigate and identify “non-redundant” components of a Protection System and has allowed significant lead time to complete the work as outlined in the Implementation plan.</p> <p>Also please refer to the SDT’s response to NSRF comments.</p>	
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
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Dislikes	0
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Response

Thank you for your comment. The SDT has added language to footnote 13d for clarity and also has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1. Industry stakeholders will have the opportunity to re-evaluate cost effectiveness in the next posting.

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

Answer	No
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Document Name	
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Comment	
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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

Thank you for your comment. The SDT has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1.

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 reliability of the Bulk Power System at lower costs than other constructions projects" there exists significant costs for associated component of the protections system.

Likes 0

Dislikes 0

Response

Thank you for your comment. The SDT is addressing directives as ordered by FERC for the revisions recommended. The SDT understands the significant work that would be required to investigate and identify "non-redundant" components of a Protection System and has

allowed significant lead time to complete the work as outlined in the Implementation plan. Without more specifics on this comments, the SDT is not able to respond with any more detail.

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

Thank you for your comment. The SDT has added language to Footnote 13d for clarity and also has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1. Industry stakeholders will have the opportunity to re-evaluate cost effectiveness in the next posting.

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

Thank you for your comment/ The SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity. Consistent with the intention of FERC Order No. 786, the SDT included the specification of known outages to be modeled based on the accompanying factors outlined in the TPL-001-5. The SDT has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1.

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

Thank you for your comment. The SDT has added language to Footnote 13d for clarity and also has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1. Industry stakeholders will have the opportunity to re-evaluate cost effectiveness in the next posting.

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	
Thank you for your comment. Please refer to the SDT's response to MRO NSRF comments.	
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	
Thank you for your comment. Please refer to the SDT's response to MRO NSRF comments.	
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	
<p>To determine if something is cost-effective, the analysis must consider alternatives to achieve a measurable outcome.</p> <p>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.</p>	
Likes	0
Dislikes	0
Response	
<p>Thank you for your comment. The SDT is addressing directives as ordered by FERC for the revisions recommended. Without more specifics on this comments, the SDT is not able to respond with any more detail.</p>	
<p>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</p>	
Answer	No
Document Name	
Comment	
<p>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</p>	

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, 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

Thank you for your comment; The SDT has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1.

The SDT has also revised and made additional clarification to the implementation plan (CAPs for such P5 events). Industry stakeholders will have the opportunity to re-evaluate cost effectiveness of these changes in the next posting.

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	
Thank you for your comment; Please refer to the SDT’s response to JEA comments.	
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	
Thank you for your comment; the SDT understands the significant work that would be required to investigate and identify “non-redundant” components of a Protection System and has allowed significant lead time to complete the work as outlined in the Implementation plan. The SDT has also removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1.	
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

Thank you for your comment. The SDT has made revisions to footnote 13d. Please see the proposed draft.

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

Thank you for your comment; Based on industry comments, the SDT has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1. With respect to Footnote 13c, the SDT concluded that single station dc supply that is not monitored or not reported at a Control Center for both low voltage and open circuit should be considered as non-redundant components of a Protection System.

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 occurrences in the industry and not required by Order No. 754.

Likes 0

Dislikes 0

Response

Thank you for your comment. Based on industry comments, the SDT has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1.

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	
<p>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.</p>	
Likes	0
Dislikes	0
Response	
<p>Thank you for your comment. the SDT understands the significant work that would be required to investigate and identify “non-redundant” components of a Protection System and has allowed significant lead time to complete the work as outlined in the Implementation plan. The SDT has also removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1.</p>	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No

Document Name	
Comment	
<p>There is some correlation between FERC directives in Order NO. 786 and Order No. 754 such as a Transmission 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."</p> <p>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.</p>	
Likes	0
Dislikes	0
Response	
<p>Thank you for your comment. The SDT is addressing directives as ordered by FERC for the revisions recommended. The SDT understands the significant work that would be required to investigate and identify "non-redundant" components of a Protection System and has allowed significant lead time to complete the work as outlined in the Implementation plan. The SDT has also removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1.</p>	
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 separate cases be developed.

Likes 0

Dislikes 0

Response

Thank you for your comment. Based on industry comments, the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4. Industry stakeholders will have the opportunity to re-evaluate cost effectiveness of the revisions in the next posting.

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 coordinating 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

Thank you for your comment. Based on industry comments, the SDT has removed the proposed P8 event and included the Table 1 extreme events (footnote 13, 2e-2h) with the current performance requirements of Planning Events of TPL-001-4 Table 1.

Industry stakeholders will have the opportunity to re-evaluate cost effectiveness of the changes in the next posting.

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

Thank you for your comment. Based on industry comments the SDT deleted Requirement R1, Part 1.1.2 and modified Requirement R2, Parts 2.1.3 and 2.1.4 to provide clarity.

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	
Thank you for your comment the SDT has updated the Implementation Plan to provide further clarification.	
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	
<p>Thank you for your comment. The SDT is addressing directives as ordered by FERC for the revisions recommended. The SDT understands the significant work that would be required to investigate and identify “non-redundant” components of a Protection System and has allowed significant lead time to complete the work as outlined in the Implementation plan. Industry stakeholders will have the opportunity to re-evaluate cost effectiveness of these changes in the next posting.</p>	
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	
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	
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-Québec 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	
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	
No comment or opinion on cost effectiveness.	
Likes 0	
Dislikes 0	

Response	
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	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
No comment	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2	

Answer	
Document Name	
Comment	
No response or comments.	
Likes 0	
Dislikes 0	
Response	

Comments received from APPA

Questions

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

- Yes
 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?

- Yes
 No

Comments:

3. Do you agree with the proposed implementation plan?

Yes

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

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

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.

End of Report