Comment Report

Project Name:	Project 2015-10 Single Points of Failure | TPL-001-5 Draft 4
Comment Period Start Date:	7/30/2018
Comment Period End Date:	9/14/2018
Associated Ballots:	2015-10 Single Points of Failure TPL-001-5 AB 3 ST 2015-10 Single Points of Failure TPL-001-5 Implementation Plan AB 2 ST

There were 51 sets of responses, including comments from approximately 148 different people from approximately 96 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. With many clarifications added to the Technical Rationale concerning details of what is meant by Footnote 13, do you agree with the contents of Footnote 13?

2. Do you agree with the removal of Requirement 1, Part 1.1.2 and changes to TPL-001-4 Requirement 2, Parts 2.1.4 and 2.4.4, in order to meet the FERC directive in Order No. 786?

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

4. Do you agree with the proposed implementation plan?

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. 754 and Order No. 786?

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Electric Reliability Council of Texas, Inc.	Brandon Gleason	2		ISO/RTO Standards Review Committee	Brandon Gleason	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Ali Miremadi	California ISO	2	WECC
					Helen Lainis	IESO	2	NPCC
					Michael Puscas	ISO New England, Inc.	2	NPCC
					Mark Holman	PJM Interconnection, L.L.C.	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC

					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	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 Powert	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
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
PPL - Louisville Gas and Electric Co.	Devin Shines	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					JULIE HOSTRANDER	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC
					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
DTE Energy - Detroit Edison Company	Karie Barczak	3,4,5		DTE Energy - DTE Electric	Jeffrey Depriest	DTE Energy - DTE Electric	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
	Kayleigh Wilkerson	5			Kayleigh Wilkerson	Lincoln Electric System	5	MRO

Lincoln Electric System				Lincoln Electric System	Eric Ruskamp	Lincoln Electric System	6	MRO
					Jason Fortik	Lincoln Electric System	3	MRO
					Danny Pudenz	Lincoln Electric System	1	MRO
Manitoba Hydro	Mike Smith	1		Manitoba Hydro	Yuguang Xiao	Manitoba Hydro	5	MRO
					Karim Abdel-Hadi	Manitoba Hydro	3	MRO
					Blair Mukanik	Manitoba Hydro	6	MRO
					Mike Smith	Manitoba Hydro	1	MRO
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC
Eversource Energy	Quintin Lee	1		Eversource Group	Sharon Flannery	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 Dominion and NYISO	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

					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					Michael Forte	Con Ed - Consolidated Edison	1	NPCC
					Peter state	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Sean Cavote	PSEG	4	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					David Kiguel	Independent	NA - Not Applicable	NPCC

					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Mike Kidwell	Empire District Electric Company	1,3,5	MRO
					Louis Guidry	Cleco	1,3,5,6	SERC
OGE Energy - Oklahoma Gas and Electric Co.	Sing Tay	6	SPP RE	OKGE	Sing Tay	OGE Energy - Oklahoma	6	MRO
					Terri Pyle	OGE Energy - Oklahoma Gas and Electric Co.	1	MRO
					Donald Hargrove	OGE Energy - Oklahoma Gas and Electric Co.	3	MRO
					John Rhea	OGE Energy - Oklahoma Gas and Electric Co.	5	MRO

1. With many clarifications added to the Technical Rationale concerning details of what is meant by Footnote 13, do you agree with the contents of Footnote 13?	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

AEP remains concerned by the increased complexity of P5 due the expansion of footnote 13. As written, this footnote requires one to consider a variety of scenarios, including backup zone 2 clearing of a transmission line for pilot relay or pilot communication failure, a breaker failure scenario initiated by trip coil failure (often the same as P4), or remote clearing of a station such as would occur upon a non-redundant bus differential failure.

In order to avoid having to evaluate zone of protection clearing times for every conceivable protection outage condition and document the "consideration" of each of the sub-items under footnote 13, AEP suggests a more generalized P5 event description by adding the text "or Remote (Delayed) Fault Clearing." As a result, it would then read: "Delayed Fault Clearing ***or Remote (Delayed) Fault Clearing*** due to the failure of a non-redundant component of a Protection System protecting the Faulted element to operate as designed, for one of the following: 1. Generator, 2. Transmission Circuit, etc."

This would continue to make use of the existing glossary term…

Delayed Fault Clearing – Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay.

This existing term covers zone 2 backup clearing of transmission lines as well as being duplicative of P4 CB failure scenarios. As a result, a new definition is necessary to cover a gap:
Remote (Delayed) Fault Clearing – Fault clearing necessary to be accomplished at stations one removed from a faulted station bus or other faulted station equipment as a consequence of a protection system single point of failure at the faulted station.

This new term is necessary because relays may not be set with an intentional time delay for clearing remote station faults, and remote clearing may be necessary for non-redundant bus differential schemes. Whether "Delayed" is included in this new term may be immaterial since, while clearing times may be long, there may be no intentional delay, just inherent delay. Footnote 13 could then removed from the draft standard, and instead, be added to the technical supplement to the standard. The would explain the possible causes of delayed clearing or remote delayed clearing, instead of rigorously having to be part of the standard and introducing what we would regard as unnecessary compliance burdens.

Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	No
Document Name	
Comment	
Footnote 13 is unnecessary. The available powerflow software doesn't simulate protection system equipement (relays, communication systems, dc supplies or control circuitry). The software simulates the transmission network. A protection system failure is simulated by making assumptions about the system's response to the failure and then simulating it. Adding specific equipment to the standand does change the simulation. Without actual protection equipment in the model, it falls on the engineer to make the correct assumptions when doing the simulations. As it should be.	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	No
Document Name	
Comment	
The phrase "comparable Normal Clearing times" is not consistent with the existing definition of "Normal Clearing" found within the Glossary of Terms Used in NERC Reliability Standards. Additionally, "comparable Normal Clearing times" is not sufficiently clear to allow consistent interpretation for purposes of enforcing the standard.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	

Comment	
Footnote 13 does not include all of the applicable single points of failure addressed by 754, such as instrument transformers, and in some cases, includes aspects that do not represent single points of failures, such as redundant breaker trip coils. With regard to breaker trip coils, the lack of two trip coils in a circuit breaker increases the potential for a breaker failure issue (P4), but does not create a relay failure issue since the absence of redundant trip coils would not prevent initiation of breaker failure for failure of a single trip coil.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
TVA agrees with the contents of Footnote 13a, b, and c. However, TVA believes Footnote 13d represents a significant cost impact for a very small probability event. Redundancy of DC control circuitry will result in significant station upgrades or, in many instances, require the construction of new switch houses. TVA believes there is not an economic justification of Footnote 13d based on the historical failure rate of DC control circuitry.	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
We suggest to clarify the wording for b), c) and d). The word “except” in parenthesis is awkward. This word perhaps could be replaced with “An exception is”…..	
Likes 0	
Dislikes 0	
Response	

Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	No
Document Name	
Comment	

Footnote 13a:

The word "comparable" in footnote 13a requires additional clarification. The Technical Rationale contains conflicting explanations of what is meant by "comparable Normal Clearing times". In the "Clarification: Is backup protection redundant?" section it appears that a secondary relay would not be considered redundant as the clearing times are not exactly the same as the primary relay. However, in the section titled "Clarification: What is comparable and what is not comparable for purposes of footnote 13?" it appears that slightly slower secondary relaying would be considered redundant if its results in "fault clearing within the expected Normal Clearing time period and isolate the fault by tripping similar System Elements". LES recommends modifying the Technical Rationale to clarify the drafting team's intent or else consider modifying footnote 13a to instead state "...that provides comparable Normal Clearing times **(e.g. piloted primary relay and non-piloted secondary relay with different Normal Clearing times)"** to ensure comparable isn't mistaken to mean having identical Clearing times.

Footnote 13c:

Is it the Standard Drafting Team's intent to consider all substations that don't have either open circuit monitoring on a single battery bank or two battery banks as non-redundant? LES feels the lack of open circuit monitoring as described in footnote 13c is too restrictive to consider a single station DC supply as non-redundant. Although the Technical Rationale section titled "Clarification: Is a battery charging system appropriate redundancy for the battery?" indicates a battery charger "may not be of sufficient power to source current necessary to operate one or more breakers", LES feels the individual utility should be permitted to analyze each substation configuration to determine if an open circuit does in fact constitute a non-redundant DC supply.

Additionally, is it the Standard Drafting Team's intent that non-redundant DC supply be modeled as an entire substation outage? This seems to be the case based on the statement "prevent the operation of all local protection" within the section titled "Clarification: Why are DC supplies addressed?". However, this is not realistic during an open circuit or low voltage situation as the relays would still be operational and only the backup protection for one line or bus section would operate during a transmission line fault. Additionally, the open circuit monitoring requirement seems unnecessary as PRC-005 provides adequate testing for open circuits. Based on this, LES recommends "open circuit" be excluded from the footnote or else additional detail added to allow for analysis of substation configuration and DC supply capability during an open circuit condition.

Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No

Document Name	
Comment	

Comments: Please consider the following:

Remove the double negative wording in 13.b, 13.c, and 13.d to make it clearer and less complicated with wording like, “shall be considered redundant”.

Add wording like, “Backup protection or a Composite Protection System is an acceptable alternative to a fully identical redundant protection if it provides acceptable System performance.” at the end of Footnote 13. A statement like this needs to be in the standard. Otherwise, it can be disregarded in an audit. In addition, replace the “Clarification: Is backup clearing redundant?” section on page 3 of the Technical Rationale with a different question and discussion like the following:

Clarification: “When is backup protection or a Composite Protection System acceptable as an alternative to fully identical redundant protection?”

If backup protection or a Composite Protection System (defined in PRC-004) provides acceptable System performance when a component of the primary Protection System fails, then fully identical redundant protection is unnecessary. Backup protection or a Composite Protection System may result in delayed clearing in comparison to a primary Protection System and trip additional Elements (refer to the NERC definition of Delayed Clearing and Normal Clearing Times). However, if any of these protection alternatives result is acceptable System performance, then fully identical redundant protection is unnecessary. If one of these protection alternatives already exist, then no Corrective Action Plan is needed. Or if one of these protection alternatives is effective, then it could be used as a suitable Corrective Action Plan in lieu of a fully identical redundant Protection System.

The terms and application of the terms in Footnote 13 do not appear to be consistent with those used in PRC-004 standard and the definition of Delayed Clearing and Normal Clearing Times in the NERC Glossy of Terms. The wording in the standard and the Technical Rationale should include and discuss the terms, Delayed Clearing and Normal Clearing Times and Composite Protection System and be consistent with them.

Add other statements at the end of Footnote 13 to clarify and confirm key matters in the TPL-001 standard so that it cannot be disregarded in an audit. The proposed wording for these statements are the following:

- “Voltage and current sensing devices of a Protection System are not considered.” Discussion of this matter is only in the Technical Rationale (p. 4) right now.
- “Protective relays (such as sudden pressure relays or thermal temperature relays) that do not respond to electrical quantities shall not be considered redundant”. Discussion of this matter is only in the Technical Rationale (p. 5) right now
- “The reclosing relays of a Protection System are not considered.” This matter is not presently discussed in the Technical Rationale.
- “Two communication systems must use separate communication paths (e.g. not be the same power line carrier line, same OPGW, same microwave tower, or same tone path, etc.) to be considered redundant. A SONET ring shall be considered redundant.” This matter is not presently discussed in the Technical Rationale.
- “Control circuitry includes everything from the DC supply through and including the trip coils, as well as auxiliary and lockout relays. A trip coils with monitoring do not need to be redundant.” This matter is not presently discussed in the Technical Rationale.

Remove the single communication system exemption when a system is monitored and reported to a Control Center. This exemption exposes Transmission Operators (TOPs) to potential noncompliance with TOP-001 (and TOP-002 if the communication failure condition continues into the next operating day). In the real time environment, TOPs must respond to the loss of communication until that pathway is repaired. Under the definition of Real Time Assessment, which is used in TOP-001, TOPs must operate within all SOLs for the topology that exists at that moment, which explicitly includes the status of protection systems. With the loss of protective function communication, the delayed clearing due to a SLG fault could cause an unacceptable system stability performance deficiency. TOPs do not have real-time stability analysis tools to keep checking pre-contingency for potential unacceptable system stability and appropriate new/temporary SOLs. Removal of the exemption would result in planning horizon analysis of non-redundant communication failures and corrective actions when unacceptable stability performance is found. Therefore, removal of the exemption would reduce the risk of TOPs being noncompliant with TOP-001 and TOP-002.	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	No
Document Name	
Comment	
The Technical Rationale does not clarify whether two communication systems must use to separate communication paths (e.g. not the same power line carrier line, single OPGW, microwave tower, tone path, etc.) to qualify as non-redundant systems. The Technical Rationale does not clarify whether control circuitry must use separate paths (e.g. not the same control panel, wire tray, etc.) to qualify as non-redundant circuitry.	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF	
Answer	No
Document Name	
Comment	

Duke Energy requests further clarification on the use of the term “monitoring” in Footnote 13 item b. Is it the drafting team’s intent, that “monitoring” should be continuous in nature, or would a once a day “check back” of the protection system meet the drafting team’s intent for monitoring? More clarification is needed on this point.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
We believe that the current draft of Footnote 13 is reasonable and will lower reliability risk. To avoid confusion, we suggest eliminating the use of double negative statements in Footnote 13. Therefore we suggest changing the phrase “shall not be considered non-redundent” to “shall be considered redundant” at the end of the sentence for 13b, 13c, and 13d.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
Please refer to comments from the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
See NSRF comments	
Likes 0	
Dislikes 0	
Response	

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	No
Document Name	
Comment	
MidAmerican Energy Company supports comments submitted by the MRO NERC Standards Reveiw Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	

Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No
Document Name	
Comment	
The term “comparable Normal Clearing times” as stated in 13.a. may cause inconsistent interpretation between entities and auditors as to what is considered comparable. Consider replacing “…without an alternative that provides comparable Normal Clearing times” with wording used in the Technical Rationale such as “…without an alternative that clears the fault within the time period expected if the single protective relay (that is simulated to fail as a SPF) were to function properly.”	

Consider replacing the double negative wording in 13.b, 13.c and 13.d ("shall not be considered non-redundant") with "shall be considered redundant."	
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 Dominion and NYISO	
Answer	No
Document Name	
Comment	
We suggest that the term "shall not be considered non-redundant" be removed in subsections b), c), and d). Also, we suggest changing the term "except" to "unless" for the three sections. In d), regarding control circuitry, we suggest the following language change: *(unless a single trip coil that is both monitored and reported at a Control Center if it is the only single point of failure in the control circuitry).*	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	No
Document Name	
Comment	
We believe that the current draft of Footnote 13 is reasonable and will lower reliability risk. To avoid confusion, we suggest eliminating the use of double negative statements in Footnote 13. Therefore we suggest changing the phrase "shall not be considered non-redundent" to "shall be considered redundant" at the end of the sentence for 13b, 13c, and 13d.	
Likes 0	
Dislikes 0	

Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	No
Document Name	
Comment	
We agree with the rational and contents of footnote 13 except for the exception for non-redundant communication equipment that is monitored and alarmed in 13b. Our concern with this exception is that teleprotection equipment that is part of a communication system may be in a failed state and not always generate an alarm.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SPP Standards Review Group (SSRG) recommends the Standards Drafting Team (SDT) provide clarity on the statement “for Normal Clearing”. NERC defines “Normal Clearing” as a situation where “[a] protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.” If a communications system associated with protective functions is installed to provide faster tripping than required, does this fall into the “Normal Clearing” definition? If so, the installed communications system associated with protective functions to clear faults faster than necessary is a single point of failure. The SSRG recommends the SDT consider adding language to the technical rationale document that explains the inclusion of the communication system associated with protective functions as a single point of failure.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; 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

No.

Westar Energy and Kansas City Power & Light Co. suggest that in Footnote 13d, single lockout relays that are monitored and report to a Control Center should be afforded the same exception as single trip coils that are monitored and reported to a Control Center.

Without the exception, the number and/or complexity of studies are unnecessarily increased with little benefit to reliability.

The companies offer the following revision:

d. A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing (except **when either** a single trip coil **or a single lock out relay** is both monitored and reported at a Control Center shall not be considered non-redundant)

Likes 0	
Dislikes 0	

Response

Douglas Johnson - American Transmission Company, LLC - 1

Answer	No
Document Name	

Comment

American Transmission Company (ATC) has concerns about the application and consistency of terms used in Footnote 13 compared to those used in other standards and the NERC Glossary of Terms, specifically Delayed Clearing and Normal Clearing Times. Reliability Standard PRC-004 introduced the term "Composite Protection System," whose definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. A failure of a Protection System component is not a Misoperation if the performance of the Composite Protection System is correct. A slower than typical operation of a Composite Protection System is considered a Misoperation if the delay results in the operation of at least one other Element's Composite Protection System. Normal Clearing Time of a Composite Protection System in the context of this standard could be interpreted as the clearing time of the slower of the redundant systems, as long as this clearing time does not result in the operation of another Element's Composite Protection Systems and acceptable system performance for the scenarios outlined in Footnote 13. However, such guidance or interpretation is currently missing from the Standard or Technical Basis.

In addition, ATC has concerns regarding the application of Footnote 13. Specifically, although monitoring of communication equipment has the potential to reduce the exposure to risk of delayed tripping, it does not eliminate the risk. By not requiring the analysis of delayed clearing on lines lacking redundant communication in the Planning Horizon, ATC (and other companies) may not identify transmission lines that need redundant communication to maintain generator or system stability. During a communication failure event, real-time operations is required to study the impact of delayed clearing for SLG or three- phase faults and mitigate any issues. This particular real-time requirement is maintained in the recent draft standards under Project 2015-09 Establish and Communicate System Operation Limits. It is not clear why the planning study requirements do not align with the operation requirements and require advance study of the same concern. Furthermore, this exemption presents a real risk to the system reliability. The Footnote 13 language transfers identification of this reliability risk into the real-time environment, where the tools used to identify dynamic instability do not typically exist. Regardless of whether the event actually occurs, the proposed Footnote 13 language creates a gap in the standards and exposes registered Transmission Operators to potential non-compliance under TOP-001 (and TOP-002, if the communication failure condition continues into the next operating day) for having failed to identify a stability related SOL and then operated the system to that limit.

In the real-time environment, ATC must respond to the loss of communication until that pathway is repaired. Under the definition of Real Time Assessment, which is used in TOP-001, ATC must operate within all System Operating Limits (SOLs) for the topology that exists at that moment, which explicitly includes the status of Protection Systems. With the loss of communication for a particular path, delayed clearing could exist for a fault and the response of the system or nearby generation may not be stable. Real-time tools would not identify the instability, and ATC would not identify the SOL to which it should have been operating. Identification of these issues should occur in the System Planning domain, where it then can be passed through to the Transmission Operator in accordance with FAC-014. The Planning environment has sufficient time to consider these scenarios to help ensure that the instability is corrected, whether that corrective action is a system reconfiguration or a new system or generator limitation for that condition.

There are additional opportunities to align terminology between PRC-005 and TPL-001 if the Standard Drafting Team continues with the use of a monitoring and alerting exemption. Some examples include "Control Center" versus "location where corrective action can be initiated" and "Open-Circuit" versus "battery continuity." Furthermore, the standard fails to address what is an acceptable monitoring period that could be used for non-redundancy or time in which corrective action would be required. Some devices are monitored in-real time, while others test less periodically, including once a day or monthly. Finally, the standard as currently written fails to address those systems that are part of non-battery-based systems.

The use of double negatives in Footnote 13 is confusing (e.g., not considered non-redundant). Consider modifying the wording of the P5 requirement to Fault plus failure of a component of a Composite Protection System which results in remote and/or delayed clearing. In this context, delayed clearing would be a delay beyond the slower of redundant systems as described above. The footnote could be simplified to state that components to be considered include protective relays, communication systems, DC supply, and control circuitry associated with the protective functions.

The redundancy of communication paths needs to be addressed. Consider the following clarification, “Communication systems are considered fully redundant if, for any single component failure such as power line carrier equipment, microwave tower, tone path, or OPGW, one communication system remains fully functional.”

ATC is concerned about the impact of mitigation of single station DC failures for stations without open circuit monitoring. Monitoring reduces the exposure to risk but cannot mitigate it. While monitoring and alerting systems are starting to become available within the industry, from ATC's perspective, they are not widely implemented. The result would be any BES facility without redundant DC supplies being tested for P5 bus section contingencies will result in delayed clearing. For the sites that fail this scenario, ATC would elect for redundant DC supplies due to future concerns about the true "redundancy" of monitored equipment. The result would likely mean building new control houses at significant cost due to space constraints at existing facilities. Finally, it is unclear as to what the appropriate evidence would be to demonstrate compliance with Footnote 13. There is no indication of what evidence type would be required to demonstrate that entities have redundancy or monitoring. Verification of redundancy of control circuitry could drive assembly of a significant number of station drawings, inventories, and other pieces of evidentiary documentation to prove redundancy. This verification has the potential to be extremely burdensome for both the industry and audit staff.	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	2015_10_Comment_MH_1.docx
Comment	
See attached comments	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	Project 2015-10 TPL-001-5 Comment_Form_Final.docx
Comment	
Likes 0	
Dislikes 0	

Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Footnote 13 items "b", "c", and "d" contain the parenthetical language "(except […] that is both monitored and reported at a Control Center shall not be considered non-redundant)". It can be argued that monitoring and reporting these quantities at a Control Center does not adequately address the potential failure of these systems when called upon to act. I.e., just because the monitoring and reporting at a Control Center indicates that these systems are functional does not necessarily mean that they will function properly when called upon. There should be no argument that redundancy in items "b", "c", and "d" is more reliable than SPFs that are monitored at a Control Center; however, Peak can accept the risk-based decision and justification that, as quoted in the rationale document, "components that may be SPF but are monitored and reported to a Control Center exhibited lower risk on par with being redundant, and therefore did not warrant P5 Event simulation."	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP agrees with the proposed language of Footnote 13, which clarifies the scope of non-redundant components.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	

The follwoing comments (1 through 5) are being submitted on behalf of the City Light SMEs: Yes - Footnote 13, specifically section a, provides a clear definition of non-redundant components of a protection system.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA believes that the clarifications are an improvement.	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
The contents of Footnote 13 now provide additional clarification of Requirement expectations as it relates to non-redundant Protection Systems. However, including this level of detail in planning assessments raises concerns: 1. Is consideration of the Protection System details even possible or practical given the state of available information and modelling tools? 2. Does the complexity of the resulting models and planning assessments create an increased opportunity for incorrect results? 3. Will it essentially create a new "design" standard that will lead to increased protection system redundancy for all transmission facilities regardless of the impact on BES reliability. 4. By considering the conditions for monitoring Protection System components (e.g. trip coil, DC Supply, etc.), there is an indirect impact on existing Requirements included in PRC-005, which also consider component monitoring when establishing maintenance periodicity.	
Likes 0	

Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
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	
While ITC generally supports the current content of Footnote 13, we would suggest the following addition. Update Footnote 13d to exclude the wiring to and from the trip coil, in addition to a single trip coil when required for Normal Clearing where it is monitored and reported. Suggested update, "A single control circuitry (including auxiliary relays and lockout relays) associated with protective functions, from the dc supply through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing (except a single trip coil and wiring that is both monitored and reported at a Control Center shall not be considered non-redundant)."	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	

Midcontinent Independent System Operator, Inc. (MISO) and New York Independent System Operator, Inc. (NYISO) do not join the ISO/RTO Council Standards Review Committee's (SRC) response to this question.

Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 1	Hydro One Networks, Inc., 1, Farahbakhsh Payam
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 1	Con Ed - Consolidated Edison Co. of New York, 3, Yost Peter
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
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	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 5	
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	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Neville Bowen, 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	Yes
Document Name	
Comment	
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	
Chris Scanlon - Exelon - 1	
Answer	
Document Name	TPL-001-5 Footnote 13 Double Negative Comment 090718.docx
Comment	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with the removal of Requirement 1, Part 1.1.2 and changes to TPL-001-4 Requirement 2, Parts 2.1.4 and 2.4.4, in order to meet the FERC directive in Order No. 786?	
Gregory Campoli - New York Independent System Operator - 2	
Answer	No
Document Name	
Comment	
The NYISO agrees that the removal of Req. 1, Part 1.1.2 will still meet the objective of FERC Order No. 786. We do not agree with the changes to Req. 2, Parts 2.1.4 and 2.4.4. We believe the assessment should be performed for all contingencies listed in Table 1, since all such contingencies are studied in the Operations Horizon. Not including all Table 1 contingencies in Req. 2 introduces a gap between the Near-term Planning and Operations Horizon assessments, poetentilally leading to a reliability gap. Other proposed NERC Standards, such as FAC-011-3, FAC-014-2, and FAC-015-1 are proposed to, among other things, improve the coordination between Planning and Operations. The proposed revisions here seem contrary to that intent.	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	No
Document Name	
Comment	
While the modifications to requirements R1.1.2, R2.1.4 and R2.4.4 are acceptable, the concerns covered by the proposed requirements R2.1.4 and R2.4.4 would be better addressed through a modification of IRO-017	
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 Dominion and NYISO	
Answer	No
Document Name	

Comment	
We find the new language difficult to interpret. We provide the following comments for consideration to make the requirements more succinct: The language seems to indicate a new procedure, or an edit to an existing procedure is required. We do not think the requirement should stipulate a new or modification to a procedure. We suggest revising the requirement as follows (applicable to both 2.1.4 and 2.4.4): *When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages expected to produce more severe System impacts on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with outage coordination procedure(s) or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. Past or current studies may be used to support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.* Additionally, the following sentence could be removed from the requirement and added to the technical rationale: *Past or current studies may be used to support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1."* The new Requirement – R2 parts 2.1.4 / 2.4.4 – is open ended and may result in Transmission Planners (TP) performing almost a "real-time" operations analysis (i.e., what is the impact of this outage / what about that outage) in-lieu of designing the Bulk Electric System (BES), which is the purpose of TPL-001. NERC IRO-017 *Outage Coordination*, which purpose states "*To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon*", was established for this purpose, and the proposed TPL-001 change would represent a spillover from IRO-017.	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
We find the new language difficult to interpret, and possibly redundant. We provide the following suggestions for consideration to make the requirements more succinct. The documented outage coordination procedure or technical rationale should cover the rationale for outage selection.	

When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed. These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration. The assessment shall be performed for the P0 and P1 categories identified in Table 1 with the System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned. Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.

Additionally –

The new Requirement – R2 parts 2.1.4 / 2.4.4 – is open ended and may result in Transmission Planners (TP) performing almost a "real-time" operations analysis in-lieu of designing the Bulk Electric System (BES), which is the purpose of TPL-001. NERC IRO-017 Outage Coordination, which purpose states "To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon", was established for this purpose, and the proposed TPL-001 change would represent a spillover from IRO-017.

IRO-017 R4 states:

Each Planning Coordinator and Transmission Planner shall jointly develop solutions with its respective Reliability Coordinator(s) for identified issues or conflicts with planned outages in its Planning Assessment for the Near-Term Transmission Planning Horizon.

The intent and requirements of IRO-017-1 R4 and proposed TPL-001-5 R2 parts 2.1.4 / 2.4.4 seem to overlap, potentially causing confusion.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

TVA does not agree with the proposed revision. These studies are already performed in the operational arena, therefore there is no benefit in recreating this analysis in the planning horizon. If issues were found in the planning horizon, the corrective action(s) would be to forego the outage or to create an operating guide. The operational cases have a more accurate near-term load/generation profile which are more appropriate for these studies. Recreating these studies in the planning horizon would add no value, but take siginificant new effort and time to complete. Outages in the planning horizon should be studied by the TP, while those in the operations horizon should be studied by the TOP.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

In our opinion, any known/planned outages of major equipment for maintenance or construction should be included in the appropriate models to be assessed for P0-P7 planning events. Therefore, Requirement 1, Part 1.1.2 needs to be retained except for the words “with a duration of at least six months”.

We propose alternative language to Part 1.1.2 as follows:

"Known outage(s) of generation or Transmission Facility (ies) scheduled in the Planning Horizon."

Modification to Part 1.1.2, as proposed above, would also allow the last bullet of Part 2.1.3 to remain as an option for a sensitivity study.

We disagree with the language proposed for new Part 2.1.4. We disagree with the phrase “selected known outages” (line 2) as we believe this is not the intent of the Commission to pick and choose which planned outages should be assessed. We disagree with the development of a "documented coordination procedure" (line 5) as Transmission Planners and Planning Coordinators do not coordinate outages. Instead, we believe that a documented methodology or collection process to obtain the outages scheduled in the Planning Horizon needs to be developed. We disagree that the proposed assessment shall be performed for only the P0 and P1 planning events (lines 8 and 9), as we do not believe these analyses are sufficient to identify areas for non-consequential load loss during times of maintenance outages. We believe that if the changes to Part 1.1.2 are included as proposed above, then much, if not all, of the proposed Part 2.1.4 can be eliminated, which would be an enhancement to the standard.

As the FERC expressed in paragraph 42 of its Order 786, "The Commission's directive is to include known generator and transmission planned maintenance outages in planning assessments, not hypothetical planned outages." In our opinion, the language included at the end of Part 2.1.4

(lines 13-16) regarding "Past or current studies may support the selection of known outage(s) …" continues to support the idea of developing hypothetical or speculative outages based on previous analysis of Table 1 Planning Events P1-P7. Clearly this does not meet the intent of the Commission to include only planned maintenance outages, and in our opinion goes well beyond the directive.

If Part 2.1.4 is to remain, we propose that the language be changed to something similar to the following:

"When known generator and transmission maintenance outages are planned in the Near-Term Planning Horizon, the impact of these maintenance outages shall be assessed. The known outages included in the models shall be supported with a documented outage collection methodology/procedure or technical rationale for inclusion developed by the Transmission Coordinator or Transmission Planner."

Our concerns for Part 2.1.4 also apply to Part 2.4.4. For the reasons stated above, we cannot support the changes proposed by the SDT to meet the FERC directive.

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No

Document Name	
Comment	
As indicated in the Applicability section of TPL-001, applicability of this requirement falls on the PC and the TP. It should be noted that the TP does not own transmission assets under the TP fuction registration. Holding a TP accountable for knowing outage status of equipment in a planning model is nonsenscial. The outage of transmission equipment is determined by those entities requesting the outage, where the burden of proof should fall on the applicable entities providing data for building models under MOD-032-1 and not the TP. As noted in R1, planning models "shall represent projected System conditions"; the TP does not have full visibility of these projected system conditions, but expects that data submitted for building of the planning models, in accordance with MOD-032-1, is as accurate as the system being projected in each of the respective planning models. Additionally, the proposed TPL-001-5 Draft 4 language "These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner. Known outage(s) shall not be excluded solely based upon outage duration." Should be removed, since the TP does not own transmission assets.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
Moving the requirement for Order No. 786 to to Requirement 2 is fine. However, MISO does not agree with the characterization of planned maintenance with respect to the role of transmission planning – which is to provide for an orderly transmission expansion program that ensures the transmission system is adequate, reliable, robust and resilient at all times in the future given the lead times associated with making necessary system improvements. This is more fully described in the response to question 3 below.	
Likes 0	
Dislikes 0	
Response	
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

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	

Comment
BPA believes that removing Part 1.1.2 is appropriate. BPA does not feel that it is appropriate to incorporate it under R2. The system assessment process and the outage process are separate and distinguishable processes that should not be dependent on each other for purposes of compliance. BPA's preference would be for the planned outages process to be in a new standard entitled Long Range Outage Coordination Process. If this is not feasible, due to being outside the scope of the project, BPA would like to see two new requirements created for known outages planned for steady state analysis and known outages planned for stability analysis. It may make sense to create new subrequirements under R3 and R4 respectively, or have them be stand alone requirements. BPA is ok with the content of the requirement, just not the location of the requirement.

Likes 0	
Dislikes 0	

Response

Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	

Comment
The new Requirement – R2 parts 2.1.4 / 2.4.4 – is open ended and may result in Transmission Planners (TP) performing almost a "real-time" operations analysis (i.e., what is the impact of this outage / what about that outage) in-lieu of designing the Bulk Electric System (BES), which is the

purpose of TPL-001. NERC IRO-017 *Outage Coordination*, which purpose states "*To ensure that outages are properly coordinated in the Operations Planning time horizon and Near-Term Transmission Planning Horizon*", was established for this purpose, and the proposed TPL-001 change would represent a spillover from IRO-017.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
We maintain that Planning Assessments and Operations Planning shall be coordinated. 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 existing standards FAC-011-3 R3 and FAC-014-2 R6, which require the Reliablity Co-ordinator (RC) also 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 contingencies that the RC would simulate when assessing and approving these outages, otherwise operations is held to more stringent/conservative performance than planning. Moreover, NERC Project 2015-09 (Establish and Communicate System Operating Limits) has proposed modifications to FAC-011-3 and FAC-014-2, and a new Reliability Standard FAC-015-1 that are aimed at improving the coordination between planning and operations. The proposed FAC-011-4 R5 requires the RC in its SOL Methodology to identify any additional single contingencies (beyond P1 contingencies) or multiple contingency events for use in performing Operational Planning Analysis and Real-time Assessments and for identifying stability limits. Hence, in order to improve this coordination between planning and operations and to eliminate any potential reliability gaps between these plans, the IESO proposes that TPL-001-5 Requirement R2 Parts 2.1.4 and 2.4.4 should require at least the same contingencies to be assessed as part of the Planning Assessment for outage conditions as the ones identified in proposed FAC-011-4 Requirement R5 Parts 5.2, 5.3, and 5.4.	
Likes 1	Hydro One Networks, Inc., 1, Farahbakhsh Payam
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	No
Document Name	

Comment
While the changes to Requirement R2 Parts 2.1.4 and 2.4.4 represent a significant improvement over the currently effective TPL-001-4, Peak has a concern related to the contingencies required for study for the outages considered in the Planning Assessment. The primary concern is the lack of continuity between planning and operations with regard to contingency analysis. Per these proposed requirements, P1 contingencies are the only contingency types required to be studied for the outage conditions. However, in the operations horizon several Transmission Operators (TOP) and Reliability Coordinators (RC) consider (and require reliable system performance for) contingencies more severe than single P1 contingencies, as specified in the RC's SOL Methodology for the Operations Horizon per FAC-011-3 Requirement R3.2, R3.3, and R3.3.1. These multiple contingencies might include certain P4, P5, or P7 multiple contingencies. If there are multiple contingencies that are required for assessment (and are required to meet performance criteria) in the operations horizon, then those same contingencies should be assessed for planned outages in the planning horizon. Excluding these contingencies from the Planning Assessments for the outage conditions creates a reliability gap between planning and operations. Under the existing language, the planner's assessment of the outages would only identify reliability problems associated with P1 contingencies, whereas, if the planners considered the same contingencies that are considered in operations, the reliability gap between planning and operations would be closed. Any identified reliability risks in the Planning Assessment would result in either rescheduling the outage or proposing solutions that could be passed on to operations. If multiple contingencies that are used in operations are not required for assessment in the planning horizon, then the outcome is an environment where operations is held to more stringent/conservative performance than planning. This presents increased reliability risks, it conflicts with good utility practice, and it detracts from the principle of "plan it like you intend to operate it, and operate it like you planned it." Furthermore, NERC Project 2015-09 (Establish and Communicate System Operating Limits) has proposed modifications to FAC-011-3 and FAC-014-2, and a new Reliability Standard FAC-015-1 that are aimed at improving the continuity between planning and operations. These proposed standards were posted for the 45-day formal comment period on 8/24/2018. The proposed FAC-011-4 Requirement R5 and subparts requires the RC in its SOL Methodology to identify any additional single contingencies (beyond P1 contingencies) or multiple contingency events for use in performing Operational Planning Analysis and Real-time Assessments and for identifying stability limits. If this standard passes ballot, then continuity between planning and operations would be further improved if TPL-001-5 R2 Parts 2.1.4 and 2.2.4 would require these same contingencies to be assessed as part of the Planning Assessment for outage conditions. Accordingly, Peak suggests that TPL-001-5 Requirement R2 Parts 2.1.4 and 2.4.4 require an assessment of not only P1 contingencies, but also the additional single contingencies and multiple contingencies identified in proposed FAC-011-4 Requirement R5 Parts 5.2, 5.3, and 5.4. It is possible that these more severe contingencies are unable to meet the performance criteria in Table 1 of TPL-001. This can be addressed by relaxing the performance criteria for these contingencies during prior outage conditions, where the assessments would only require that these contingencies demonstrate that instability, Cascading, or uncontrolled separation does not occur. Such a requirement actually provides even more alignment between planning and operations, considering proposed FAC-011-4 Requirements R6 parts 6.3 and 6.4 which stipulate that the performance criteria for contingencies more severe than single P1 contingencies are that the system demonstrates that instability, Cascading, or uncontrolled separation does not occur. Peak also has a concern with the language in TPL-001-5 R2 Parts 2.1.4 and 2.2.4 that states, "System peak or Off-Peak conditions that the System is expected to experience when the known outage(s) are planned." Peak believes that the "or" should be "and", thus requiring the outages to be assessed against both System peak conditions and against Off-Peak conditions. If the outages are not assessed against both System Peak and Off-Peak conditions, there is an increased risk that significant reliability issued could go undetected. Peak does not believe that the determination of using System Peak versus Off-Peak conditions for this analysis should rely on engineering judgement. Alternately, the System Peak and Off-Peak language could be removed and replaced with "the range of system conditions that the System is expected to experience during the outage."

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
The proposed removal of the six month minimum duration threshold for modeling planned outages introduces duplication of the studies currently performed in TOP-003 and IRO-017 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	

Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
The relocation and revisions to wording related to the identification and treatment of known outages in the Near-Term Planning Horizon appear to address both the FERC and industry issues and concerns.	
Likes 0	
Dislikes 0	
Response	

Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
MISO and NYISO do not join the SRC's response to this question.	

Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	Yes
Document Name	
Comment	
It clarifies the requirement	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Removing Requirement 1, Part 1.1.2 makes sense as the base models should reflect the longer-term state of the system and not scheduled outages or contingency events. The changes to TPL-001-4 Requirement 2, Parts 2.1.4 and 2.4.4 are logical and allow for knowledgeable, technical rationale to determine which scheduled outages need to be analyzed. Note: references to "Near-Term Planning Horizon" should be replaced with the defined term from the NERC Glossary of Terms - "Near-Term Transmission Planning Horizon".	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	

Comments: GTC agrees in principle with the changes to Requirement 2, Parts 2.1.4 and 2.4.4. However, we recommend the following format changes and minor content changes to clarify the requirements:

2.1.4 When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed.

2.1.4.1 These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner.

- Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.
- Known outage(s) shall not be excluded solely based upon outage duration.

2.1.4.2 This assessment shall include, at a minimum, known outages expected to produce more severe System impacts on the Planning Coordinator's or Transmission Planners's portion of the BES.

2.1.4.3 The assessment shall be performed for the P0 and P1 categories, identified in Table 1, for the System peak or Off-Peak conditions expected when the known outage(s) are planned.

2.4.4 When known outage(s) of generation or Transmission Facility(ies) are planned in the Near-Term Planning Horizon, the impact of selected known outages on System performance shall be assessed.

2.4.4.1 These known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure or technical rationale by the Planning Coordinator or Transmission Planner.

- Past or current studies may support the selection of known outage(s), if the study(s) has comparable post-Contingency System conditions and configuration such as those following P3 or P6 category events in Table 1.
- Known outage(s) shall not be excluded solely based upon outage duration.

2.4.4.2 This assessment shall include, at a minimum, known outages expected to produce more severe System impacts on the Planning Coordinator's or Transmission Planners's portion of the BES.

2.4.4.3 The assessment shall be performed for the P1 categories, identified in Table 1, for the System peak or Off-Peak conditions expected when the known outage(s) are planned.

One additional comment is concerning the "documented outage coordination procedure or technical rationale" by which Planning entities determine the appropriate outages to be assessed. The SDT included the following statement in the technical rationale that accompanied this posting:

"The documented outage coordination procedure is intended to include consultation with the affected Reliability Coordinator, consultation with Transmission and/or Generator Owner(s) affected by the known outage, or application of documented outage coordination processes."

This is a reasonable assumption but it is important to note there is no requirement for operating entities to provide this type of information to planners for all planned outages. The method which an auditor would use to determine the adequacy of a planner’s procedure/rationale is unclear, in instances where planning entities do not have access to operating plans as they are produced or changed •	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
See NSRF comments	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
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	

We propose the following alternative text for Part 2.1.4: "…for the P0 and P1 categories identified in Table 1 with expected System conditions when the known outage(s) are planned." Similarly we proposed the following alternate text for Part 2.4.4: "…for the P1 categories identified in Table 1 with expected System conditions when the known outage(s) are planned." The System peak or Off-Peak models will normally be suitable for the Part 2.1.4 and 2.4.4 requirements. However, explicitly requiring the assessment obligation to be based on only these models excludes the option of using other models that can represent the applicable system conditions more appropriately than the System peak or Off-Peak models.

Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	

Yes for R1.1.2 removal. - The removal is just fine, because it streamlines or simplifies R1 objective, and the sub-requirement that pertain to inclusion of known outages to near-term planning horizon cases will be addressed on future requirement R2.1.4 (for steady state) and R2.4.4 (transient stability), anyway.

Yes for R2.1.4 and R2.4.4. – The proposed requirement gives the TP the choice of selecting which known outages can be included in the assessment, which are primarily outages that may pose severe system impacts to the system only. These may prove to be helpful, because the focus of the study relies only on the selection and inclusion of known outages that may cause severe system impacts to the system.

Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	

No comments

Likes 0	
Dislikes 0	

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

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Neville Bowen, 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	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; 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	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
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	
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	
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	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
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	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE appreciates the Standards Drafting Team's (SDT) reconsideration of Requirement language to address the comments previously submitted by Texas RE. The changes to TPL-001-5 R2, Part 2.1.4 appear to address the circular issue of R1 pointing to R2 and R2 pointing to R1.

Texas RE still contends there should be a specific requirement for the Planning Coordinators and Transmission Planners to develop an outage coordination process with specific criteria. As currently drafted, Part 2.1.4 and Part 2.4.4 state known outage(s) shall be selected for assessment consistent with a documented outage coordination procedure *or* (emphasis added) technical rationale by the Planning Coordinator or Transmission Planner. Texas RE's position is that a technical rationale is not sufficient and there is no Reliability Standard that requires Planning coordinators and Transmission Planners to develop an outage coordination procedure. IRO-017-1 R1 requires each Reliability Coordinator to develop, implement, and maintain an outage coordination process for generation and Transmission outages within its RC Area.

Texas RE previously submitted comments including proposed language to R1 that would require each Transmission Planner and Planning Coordinator to maintain System models that include known outages of generation or Transmission Facilities. Texas RE again recommends revising TPL-005 R1.1 as follows:

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.

Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF	
Answer	
Document Name	
Comment	
How does new 2.1.4 meet the SDT's belief stated in the Technical Rationale that there is an "implied need to strengthen the collaboration and consultation between the Reliability Coordinator and the planning entities at the outset of determining the known outages that should be assessed in the Near-Term Transmission Planning Horizon." What is the measurement of whether the Technical Rationale developed under 2.1.4 is acceptable – simply that is not based on duration of the outage? How does having a documented outage coordination procedure satisfy the need for performing TPL analysis? Most entities already have such a process that is totally unrelated to TPL analysis. While it may be implied, the documented outage coordination procedure does not explicitly state that any modeling or contingency analysis is required.	
Likes 0	
Dislikes 0	
Response	

3. Do you agree with the proposed revisions to TPL-001-4?	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
PacifiCorp does not agree with the proposed removal of Requirement 1, Part 1.1.2 and changes to Requirement 2, Parts 2.1.4 and 2.4.4 for the reasons stated in question 2 above. PacifiCorp agrees with all other proposed revisions to TPL-001-4.	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	No
Document Name	
Comment	
Yes and no. See comments provided for questions 1 and 2.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

As stated in our response to Question #1, AEP remains concerned by the increased complexity of Footnote 13 driven by its excessive detail. The version of Table 1 that is currently in effect is clear in its intent and application, however, we believe that Footnote 13 as currently proposed actually *removes* the clarity that was once there.	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	No
Document Name	
Comment	
SDG&E agrees with all revisions to TPL-001-4 except those related to P5 planning events for non-redundant components of a Protection System identified in footnote 13.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	

We maintain that the Contingency event that represents a 3 ph fault plus a failure of a non-redundant component of a Protection System remains a reliability concern and reiterate that the SDT's alternatives offered in Draft #1 and Draft #3 would address it:

- Keep the 3ph fault + SPF in Protection System event in Table 1 Stability Performance Extreme Events, but require a Corrective Action Plan when Cascading is identified.
- Move the 3 ph fault + SPF in Protection System event to Table 1 Steady State & Stability Performance Planning Events and create a new P8 category. The only System performance requirement that should apply to P8 is that Cascading shall not occur and a Corrective Action Plan should be required when Cascading is identified.

The existing evaluation (except to separate breaker failure from the SPF in Protection System event) brings us back to square one.	
Likes 1	Hydro One Networks, Inc., 1, Farahbakhsh Payam
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates	
Answer	No
Document Name	
Comment	
In the Extreme Events portion of Table 1, the use of the NERC defined term "Normal Clearing" is not sufficiently clear or could be misapplied. A composite protection system can be made up of redundant systems with significantly different clearing times. Failure within a redundant composite protection system can be interpreted as "Normal Clearing" based on the NERC definition of a "Misoperation". Using this definition, "Normal Clearing" would occur without providing clearing fast enough to meet stability requirements. Steady State and Stability Performance Extreme Events should be evaluated by simulating "worst case clearing time" of the composite protection system for the element(s) unless otherwise specified. The use of the term "Delayed Fault Clearing" in the Stability Items 2e through 2f of the Extreme Events portion of Table 1 could be interpreted differently based on the NERC definition of "Delayed Fault Clearing". The NERC definition of "Delayed Fault Clearing" seems to apply to failures of an entire composite protection system, whereas clearing occurs via breaker failure or some remote clearing after an intentional delay. Using this interpretation of the definition, the failure of a portion of a redundant system which results in a slower clearing time would not meet the definition of "Delayed Fault Clearing", but could still result in clearing that does not meet stability requirements. Stability Items 2e through 2f of the Extreme Events portion of Table 1 should be studied under conditions where failure of a non-redundant component results in "worst case clearing time" for the composite protection system of the element(s).	
Likes 0	
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	
Comment	
See question 2	
Likes 0	

Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
For the same reasons stated in question 2. BPA believes that removing Part 1.1.2 is appropriate. BPA does not feel that it is appropriate to incorporate it under R2. The system assessment process and the outage process are separate and distinguishable processes that should not be dependent on each other for purposes of compliance. BPA's preference would be for the planned outages process to be in a new standard entitled Long Range Outage Coordination Process. If this is not feasible, due to being outside the scope of the project, BPA would like to see two new requirements created for known outages planned for steady state analysis and known outages planned for stability analysis. It may make sense to create new subrequirements under R3 and R4 respectively, or have them be stand alone requirements. BPA is ok with the content of the requirement, just not the location of the requirement.	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
See comments for question 2.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	

Comment
MISO supported the changes previously proposed by the SDT to create the P8 contingency. Given that a Corrective Action Plan is needed to address instability or cascading resulting from a three-phase fault and subsequent failure of a non-redundant protection system component, the best way to achieve this requirement is through the creation of a P8 contingency rather than extreme events. Therefore, MISO agrees with the proposed P8 event. MISO would also support expanding the P5 contingency definition to include both a phase-to-ground fault and a three-phase fault as well should the Standard Drafting Team prefer to expand the P5 contingency definition rather than establish a new P8 event. The aspects of the current TPL-001-4 and proposed TPL-001-5 standards that address the area of planned maintenance outages mischaracterize the role of transmission planning – which is to provide for an orderly transmission expansion program that ensures the transmission system is adequate, reliable, robust and resilient at all times in the future given the lead times associated with making necessary system improvements. Adequacy, reliability, robustness, and resilience include the flexibility of a transmission system to allow for the planned outage of any single transmission facility during non-peak periods in a manner that i) does not require the curtailment of firm load and ii) provides for the system to be operated in an N-1 secure state after the single transmission facility has been removed from service for planned maintenance or other purposes. All transmission facilities require planned outages from time-to-time to facilitate maintenance and repair work that cannot be performed hot, to facilitate capital upgrades to the transmission system or other facilities in the vicinity of the transmission facility, or for other purposes. Therefore, the eventual occurrence of a future planned outage on a transmission facility is certain and “known”, not “hypothetical”, only the timing and duration of the future outage could be considered uncertain or “hypothetical”. If the transmission system is not planned in a manner that allows for any single facility to be removed for maintenance under non-peak conditions, then the system will not maintain the necessary adequacy, robustness and flexibility to accommodate maintenance requirements in general. In FERC Order 786, the Commission indicated the following at PP 41: “We agree with commenters such as MISO and ATCLLC that certain elements may be so critical that, when taken out of service for system maintenance or to facilitate a new capital project, a subsequent unplanned outage initiated by a single-event could result in the loss of non-consequential load or may have a detrimental impact to the bulk electric system reliability. A properly planned transmission system should ensure the known, planned removal of facilities (i.e., generation, transmission or protection system facilities) for maintenance purposes without the loss of non-consequential load or detrimental impacts to system reliability such as cascading, voltage instability or uncontrolled islanding.” (emphasis added) It is “known” that every transmission facility will eventually need to be taken out of service for planned maintenance or other purposes, thus the proper planning approach to planned maintenance outages should be to ensure that the transmission system is planned with sufficient robustness and resilience to accommodate the planned maintenance flexibility during off-peak periods that will be required regardless of whether or not such activity has been scheduled at the time the planning assessment is conducted. While some have argued that outages can be fully managed by outage coordination efforts focused on the operating horizon, if the system is not planned and expanded to maintain sufficient adequacy and robustness to support future outages, the outage coordination functions may be backed into a corner where there is no choice but to shed load to accommodate a planned outage (which is generally considered unacceptable) or deny an outage given the inability of the outage coordination function to make the necessary system upgrades in the operating horizon that should have been made by the planning function within the planning horizon. An important function of planning is to support operations, which includes ensuring the system is adequate and robust enough to provide flexibility to the outage coordination function to schedules planned outages when they are needed without sacrificing reliability or load continuity. A proposed remedy would be to expand the P3 and P6 contingency definitions to evaluate an additional multiple outage scenario with no load loss. This scenario would include a planned outage, system adjustments, and then a contingency, but no consequential or non-consequential load loss would be allowed for the planned outage element, and no non-consequential load loss would be allowed for the contingent element. This contingency definition, which would be applicable only for non-peak conditions where planned maintenance is normally performed, could be

implemented as a P2.1 contingency, followed by system adjustments (but no load shed), followed by a P1 contingency. With this new contingency added, the system would be planned to accommodate the planned outage of any one system element (transmission or generation element) during off-peak periods while ensuring the system can continue to operate in a manner that is N-1 secure with no non-consequential load loss. Use of the P2.1 contingency as the maintenance contingency ensures continuity of service to load for the maintenance outage, which aligns with how the system would be operated. This change to the standard ensures that there is a minimal level of flexibility to provide for the planned outage of any single element in the system, which better aligns with the overall goal of transmission planning to ensure the system is adequate, robust, resilient, and reliable in the future.

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	No
Document Name	

Comment

The standard should be revised to represent the true intent for this standard, which is to hold the PC and TP accountable for assessing the state of the transmission system under specific scenarios, determine deficiencies, and act to correct those deficiencies. Requirements outside of the control of the TP are not an effective tool to determine if the intent of those requirements has been met. The TP can only assume that transmission equipment outages that represent a future timeframe (year one or year two), have been submitted by the entity requesting the outage, and are correct.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

See proposed changes to Requirements 1 (Part 1.1.2) and 2 (Parts 2.1.4 and 2.4.4) above.

Clarification in needed on 'Table-1 – Extreme Events Second Column Stability Item 2f'. This should be changed to 3-phase close-in fault on Transmission circuit with failure of a non-redundant component of a Protection System result in Delay Fault Clearing. The FERC Order 754 study only looked at close-in line and bus faults with remote clearing. For end of line 3-phase faults, fault detection is unlikely with a failure of a non-redundant battery due to in-feed effect. It is not possible to run a stability study with this indeterminate state. The requirement as written will require installation of redundant batteries or battery monitors at all BES substations. If this is the case corrective action plans may take years to complete. Given the low probability of a battery failure concurrent with a 3-phase end of line fault, was this the intent of the standard? Also, for end of line faults can credit be given for the chargers ability to trip?	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
TVA believes that the proposed changes to Footnote 13d creates a significant cost impact for a very small probability event. TVA believes that the proposed changes to Requirement 2, Parts 2.1.4 and 2.4.4 would add no value and create siginificant new effort and time to duplicate operations studies.	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
. Please see comments in question 1 and 2 above.	

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	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
See NSRF comments	
Likes 0	
Dislikes 0	
Response	
Jeffrey Watkins - Jeffrey Watkins On Behalf of: Kevin Salsbury, Berkshire Hathaway - NV Energy, 5; - Jeffrey Watkins	
Answer	No

Document Name	
Comment	
NV Energy feels it is prudent to require a corrective action plan resulting from a three-phase fault and subsequent failure of a non-redundant protection system component, and should therefore not be considered an extreme event, but rather a planning event. NV Energy did not agree with the changes previously proposed by the SDT to create a new P8 contingency, but would support expanding the P5 event to include a three phase fault or a L-G fault, or replacing the L-G fault type with a three phase fault.	
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 Dominion and NYISO	
Answer	No
Document Name	
Comment	
Please see comments in question 2 above regarding known outages. The current title of the technical rationale document is misleading as it could be interpreted as the technical rationale for single points of failure only, instead of TPL-001-5 as a whole. We request that the title of the technical rationale be changed to "TPL-001-5 Technical Rationale." The language in 2.1.5 should be modified to align with 2.4.5 as shown below: *When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed. Based upon this assessment, an analysis shall be performed for the P0, P1, and P2 categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.* Additionally, per the SDT's response to the last round of comments submitted, please add language in the technical rationale to clarify on what is meant by the spare equipment strategy. For reference, below were the comments submitted – *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.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; 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	
No. Westar Energy and Kansas City Power & Light incorporate by reference their response to Question 1.	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
The addition of new single point of failure of selected non-redundant Protection System Components to the P5 contingency event category seems appropriate. Elimination of the P8 contingency event category and moving the new single point of failure of selected non-redundant Protection System Components to the Extreme Events category seems appropriate. The language in Footnote 13 is still a concern, as noted in ATC's comments on Question 1 above.	

Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	No
Document Name	
Comment	
See comments for question 1.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP supports the proposed revisions as drafted.	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Seattle City Light agrees with the proposed revisions to the TPL-001-4. The definition of the non-redundant components of protection system is also adequate and provides clarity to the definition of non-redundant components of protection system.	

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	
We agree with the proposed revisions except as noted on this Comment Form.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	

We agree with the proposed revisions except as noted on this Comment Form.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC thanks the SDT for their work on developing this revision to the TPL-001 and agrees with the work they have done so far. ITC does not believe though that the language for the Requirements 3.5 and 4.5 for the evaluation of the non-redundant component of a protection scheme goes far enough. While it does require industry to evaluate the consequences of the configurations, it does not require a Corrective Action Plan be developed for any significant affect to the transmission system. ITC believes a CAP should be required.	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
Answer	Yes
Document Name	
Comment	
Studying the steady-state and dynamic impacts of events involving the non-operation of single elements of a Protection System as well as notable scheduled outages is worthwhile in order to maintain transmission system reliability.	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	Yes

Document Name	
Comment	
It is appropriate	
Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
MISO and NYISO do not join the SRC's response to this question.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	Yes
Document Name	Project 2015-10 TPL-001-5 Comment_Form_Final.docx
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
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	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Neville Bowen, 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	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Please see Texas RE’s response to #2.	
Likes 0	
Dislikes 0	
Response	

4. Do you agree with the proposed implementation plan?	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
The first timeframe following FERC's approval of TPL-001-5 needs to be 5 years, rather than 3 years, to perform all the required tasks (e.g., make model changes; develop the new Footnote 13 contingencies; perform the new known outage, long lead time, P5, and Extreme event analyses; and develop CAPs for non-P5 contingency system deficiencies). The timeframes of 2 years and 4 years to complete the other required tasks seem acceptable.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	
The SSRG notes that after the 48-month implementation sunset provision has expired, the implementation plan will not provide an entity with sufficient time to implement a Corrective Action Plan (CAP) identified in future annual planning cycles. For example, a CAP that identifies a facility that will require longer than one year to construct will not be in-service by the next annual planning cycle, which will impact the Planning Coordinator's (PC) the ability to meet the Table 1 performance requirements for the next annual planning assessment. In other words, an unintended and unavoidable consequence of the requirement may be a violation of R2.7 through no fault of the PC performing the annual study and preparing the CAP. A solution to the issue would be to include an exception in Section 2.7.3 or create a new Section 7.2.4 that alleviates the need to meet the Table 1 performance metrics for subsequent planning assessments when P5 events identify a capital project as a CAP and no other mitigation can be achieved. The exception would be extended until the capital project can be placed into operation.	
Likes 0	
Dislikes 0	
Response	

Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	No
Document Name	
Comment	
Depending on the different mitigations, it may take longer to implement.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
See NSRF comments	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
Please refer to comments from the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Mark Holman - PJM Interconnection, L.L.C. - 2	
Answer	No
Document Name	
Comment	

- PJM planning procedures do not allow for redispatch to address reliability criteria violations. Based on this, PJM has some concerns regarding requirements to fully implement Corrective Action Plans in accordance with the identified schedule. As the RTO, PJM does not have control over the construction schedule, and relies on individual Transmission Owner to complete construction and implement enhancements by the required in service date detailed in the Corrective Action Plan.

- The sentence "The first annual Planning Assessment shall be completed in accordance with TPL-001-5, but without CAPSs for revised P5, by this date." in Figure 1 of the Implementation Plan could use some clarification. PJM in concerned that the sentence implies that revised P5 events, while not requiring a CAP, still need to be included in the Planning Assessment at the t+36 Point on the timeline. PJM Proposes the following revisions to clarify that revised P5 events are not required for inclusion in the assessment during this first 36 month period: “The first annual Planning Assessment (excluding revised p5 events), shall be completed in accordance with TPL-001-5, but without CAPs for revised p5, by this date.”

Likes 0	
Dislikes 0	
Response	

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

Duke Energy does not support the proposed Implementation Plan. Without knowing at this time the potential size and scope of the work that will be necessary for implementing the CAPs, we cannot agree on the 48 month portion of the Implementation Plan. These corrective actions will likely involve improvements to protection systems for BES elements and these require system outages to critical lines that are only made available during low-load periods that will extend the overall time required to complete the CAP. We disagree with assigning an implementation period to an unknown scope of work. We suggest the SDT consider a flexible Implementation Plan with phases that can be assessed depending on the size and scope of work.

Likes 0	
Dislikes 0	
Response	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	
Comment	
It would be better for the first timeframe to be 4 or 5 years, rather than 3 years, from FERC approval of TPL-001-5 to make the model changes, develop the new contingency files, perform the additional analysis, and developing CAPs for non-P5 contingency system deficiencies. The second timeframe of 2 years and third timeframe of 4 years to complete the other required tasks seem acceptable.	
Likes 0	
Dislikes 0	
Response	
Robert Ganley - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	
Since we have concerns with some proposed revisions, (please see comments in question 1 and 2 above) we feel it is premature to consider a specific implementation plan.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
While the implementation timelines to study and develop CAPs are reasonable, TVA does not agree with the implementation timeline for completing CAPs to address the modified P5 events. These changes will require extensive work in order to make protection systems completely redundant for these events, requiring switch houses in some cases. If several switch houses are required, the proposed implementation plan would not provide adequate time to coordinate extensive outages and complete the corrective action plans.	

Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
We do not agree with the proposed edits or non-TP related requirements, hence we do not agree with the proposed implementation plan, at this time.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
We believe the changes recommended above need to be made before we agree with an implementation plan.	
Likes 0	
Dislikes 0	
Response	
Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6	
Answer	No
Document Name	
Comment	
More time is needed to implement the proposed changes.	

Likes 0	
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	
Comment	
See question 2.	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	No
Document Name	
Comment	
As we have mentioned before, SDG&E does not agree with the changes related to P5 planning events for non-redundant components of a Protection System identified in footnote 13. Unfortunately, a great deal of the changes to the implementation plan are to allow time for the Transmission Planners to coordinate with protection engineers on addressing these new requirements.	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	Project 2015-10 TPL-001-5 Comment_Form_Final.docx
Comment	

Likes 0	
Dislikes 0	
Response	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Standards Review Committee	
Answer	Yes
Document Name	
Comment	
MISO and NYISO do not join the SRC's response to this question.	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	Yes
Document Name	
Comment	
The California ISO supports the comments of the ISO/RTO Council Standards Review Committee (SRC)	
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	
We believe that the proposed implementation plan is reasonable. A significant amount of protection and controls related data and design drawings will have to be accessed and reviewed in order to facilitate the ability to study the required additional dynamic simulations.	

Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
SCL agrees with the implementation plan and the timeline given to accomplish the plan.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
The implementation plan profides sufficient time to perform studies and coordinate CAPs with external entities to meet compliance with TPL-001-5.	

Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 3, 1, 5; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Neville Bowen, 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	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; 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	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
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	
Quintin Lee - Eversource Energy - 1, Group Name Eversource Group	
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	
Greg Davis - Georgia Transmission Corporation - 1	
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 Dominion and NYISO	
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	

Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
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	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1, Group Name Manitoba Hydro	
Answer	
Document Name	
Comment	
The legal framework in Manitoba Hydro's jurisdiction does not permit the use of an implementation plan. The proposed NERC 9-year implementation plan appears reasonable.	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE appreciates the SDT's attempt to clarify the implementation plan and the timeline provided is helpful. Texas RE recommends explicitly saying which requirements are applicable in the Compliance Date and Initial Performance date sections. Based on the words written (not on the visual timeline), Texas RE understands the IP as follows:

- 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, 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, **which is redundant and could cause confusion**.
  - 108 months following regulatory approval
    - In accordance with the Compliance Date section, for CAPs developed to address failures to meet Table 1 performance requirements for the p5 planning event for the non-redundant components of a Protection System identified in footnote 13 items a, b, c, and d, or 36 plus 72, or 108 months following the effective date of the applicable governmental authority's order approving the standard.

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 NSRF.	
Likes 0	
Dislikes 0	
Response	

5. Are the proposed revisions to TPL-001-4 along with the Implementation Plan a cost effective way of meeting the FERC directives in Order No. 754 and Order No. 786?	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
PacifiCorp believes that the proposed revisions to TPL-001-4 to model known outages with a duration of less than six months in the annual Planning Assessment are not a cost effective way of meeting FERC directives in Order No. 786 as these studies are already being performed in TOP-003 and IRO-017 Operational Planning Assessments. PacifiCorp agrees that the proposed revisions to TPL-001-4 along with the Implementation Plan are a cost effective way of meeting FERC directives in Order No. 754 addressing reliability issues associated with single points of failure in protection systems.	
Likes 0	
Dislikes 0	
Response	
Christopher Overberg - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	
Comment	
See question 2	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	

Comment	
BPA believes that the revision to the standard and the implementation plan do not adequately address industry concerns about the costs needed to plan and construct a project for a planned maintenance outage of short duration. Those planned maintenance outages will be coordinated ahead of time according to outage planning processes. It is not cost effective to plan and construct a project for a planned maintenance outage of short duration when planned outages of the same facility are not expected again in the foreseeable outage planning timeframes. Requiring a low-probability, single-point-of-failure of protection systems to be analyzed as a Planning Event is beyond prudent planning. The proposed changes could be a very-significant burden on Planning and Engineering staffs to investigate and identify “non-redundant” components of a Protection System. The proposed changes to the standard would require industry to protect against rare three-phase faults coupled with protection system failure. This should remain as an extreme event and allow the TP or PC to decide whether mitigating possible Cascading is cost effective. The cost effectiveness document falls short of providing any substantive cost effectiveness analysis and is more like a repeat of the proposed changes to the requirements & footnote 13.	
Likes 0	
Dislikes 0	
Response	
Terry BIlke - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	
Since the standard does not meet the objective of Order No. 754, the question of whether or not it is cost effective is moot.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	

FERC directives, cost effective or not, are a direct order of action which in accordance with the directive, if the directives determine that transmission system deficiencies exist being detrimental to state of the transmission system, those deficiencies should be acted on and corrected. Allowing more time (+12 months to all milestones) for the implementation as a result of these changes, may minimize the financial impact.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
Answer	No
Document Name	
Comment	
TVA does not believe the proposed changes to Footnote 13d are a cost effective approach. Redundancy of DC control circuitry will result in significant station upgrades or, in many instances, require the construction of new switch houses. TVA believes there is not an economic justification of Footnote 13d based on the historical failure rate of DC control circuitry.	
Likes 0	
Dislikes 0	
Response	

Robert Ganley - Long Island Power Authority - 1	
Answer	No
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	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
See comments in Question 1 regarding the acceptability of backup protection or Composite Protection System if they provide acceptable System performance. It is not cost effective to require the costlier installation of fully identical redundant primary protection when the primary protection happens to be faster and trip fewer Elements than acceptable backup protection or a Composite Protection System. It is unclear what evidence would be sufficient to demonstrate compliance with Footnote 13. An onerousFor example, the assembly of sufficient evidence of redundant control circuitry for an audit may involve the compilation of hundreds of station schematic drawings, wiring drawings, and photos, beside description documents that may be needed to explain the substation evidence. Sufficient evidence to demonstrate redundant communications and DC supplies may be similarly burdensome.	
Likes 0	
Dislikes 0	
Response	

Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	No
Document Name	
Comment	
The proposed addition of “non-redundant” components of a Protection System, in particular Footnotes 13.b. and 13.d., to this Standard may add significant resource and financial burden to Transmission Owners (TOs) that in all cases may not provide a benefit to BES reliability. Although a planning standard, the Requirements as proposed may indirectly result in TOs expanding internal “design” standards to implement redundant Protection Systems on all transmission facilities regardless of the impact on BES reliability. As an alternative approach, the SDT could consider addressing the FERC directives by expecting planning assessments be performed with the assumption that all Protection Systems are non-redundant, and then when concerns are identified, the entity would confirm that there is a redundant Protection System in place or develop a CAP to address the non-redundant Protection System. Other than increasing the scope of the planning assessments, this type of process to investigate concerns as they are identified, might eliminate the initial administrative burden on collecting detailed Protection System information and building models with sufficient detail and accuracy. It would also avoid the unintended consequence of TOs upgrading all transmission facilities with non-redundant Protection Systems, regardless of the impact on BES reliability.	
Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
Please refer to comments from the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Terry Harbour - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
Document Name	
Comment	
See NSRF comments	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
ITC does not believe it is cost effective to study the consquences of non-redundant protection devices and not require a CAP for these scenarios should their affect on the transmission system be significant and detrimental. ITC believes if the results of a study of these types of events show this, a CAP should be required.	
Likes 0	
Dislikes 0	

Response	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	No
Document Name	
Comment	
It is not clear whether this will be cost effective at this point.	
Likes 0	
Dislikes 0	
Response	
John Pearson - John Pearson On Behalf of: Michael Puscas, ISO New England, Inc., 2; - John Pearson	
Answer	No
Document Name	
Comment	
While the modifications to requirements R1.1.2, R2.1.4 and R2.4.4 are acceptable, the concerns covered by the proposed requirements R2.1.4 and R2.4.4 would be better addressed through a modification of IRO-017.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; 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	

No.

Westar Energy and Kansas City Power & Light's incorporate by reference their response to Question 1.

Without the exception offered in response to Question 1, the number and/or complexity of studies are unnecessarily increased with little benefit to reliability.

Likes 0	
Dislikes 0	

Response

Douglas Johnson - American Transmission Company, LLC - 1

Answer	No
Document Name	

Comment

ATC has concerns about that current Implementation Plan and cost-effectiveness of the proposed revisions to TPL-001-4. The current proposed language for Footnote 13 leaves uncertainty in applicability and potential gaps in studies through the use of exemptions, as noted in ATC's comments on Question 1 above. Furthermore, the uncertainty in the amount evidence to prove redundancy and/or monitoring has the potential to be a significant work effort. Regarding studies that are to be performed, the proposed TPL-001-5 standard and Implementation Plan are cost-effective, with the exception being the first 3-year timeframe of the Implementation Plan, as noted in ATC's comments on Question 4 above.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

The proposed revision and 9-year implementation plan may be a reasonable way of meeting the FERC directive. However, MH feels that the analysis and mitigation of 115 kV and 138 kV stations is burdensome and likely expensive without necessarily improving overall BES reliability. As a result, we propose the following:

1. Implementing a risk based assessment to identify critical facilities of concern rather than making full protection redundancy a bright line requirement for all BES facilities.

2. For P5 definition of HV limit should be considered from 200 to 299kV.

GENERAL COMMENT

MH will be unable to adopt this standard as a NERC standard based on legislative restrictions in Manitoba. However, changes proposed in TPL-001-5 that are acceptable to MH would be adopted in a future Manitoba standard, MH-TPL-001-5.

Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	Project 2015-10 TPL-001-5 Comment_Form_Final.docx
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

The lead time provided in the Implementation Plan allows entities to meet compliance in a cost-effective manner.

Likes 0	
Dislikes 0	
Response	
Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
It meets both FERC directives. Whether it's cost effective or not remains to be seen.	
Likes 0	
Dislikes 0	
Response	
Sing Tay - OGE Energy - Oklahoma Gas and Electric Co. - 6, Group Name OKGE	
Answer	Yes
Document Name	
Comment	
OKGE supports the language contained in Footnote 13 that allows monitoring of an element rather than requiring redundancy because it mitigates the financial burden placed on the TO and GO to maintain true redundancy elements to protect their system.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	

Answer	Yes
Document Name	
Comment	
The SSRG supports the language contained in Footnote 13 that allows monitoring of an element rather than requiring redundancy because it mitigates the financial burden placed on the TO and GO to maintain true redundancy elements to protect their system.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
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	
Mark Holman - PJM Interconnection, L.L.C. - 2	
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	
Richard Vine - California ISO - 2	
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 Dominion and NYISO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
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	

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; Neville Bowen, 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	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	
Document Name	
Comment	
Abstain	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
We believe that meeting FERC Order 786 has nothing to do with cost effectiveness. While we agree with the concept of requiring redundant system protection elements only where they are needed, per Order 754, the process of having system protection engineers perform analysis for each BES facility to determine clearing times for failures of non-redundant system protection elements is burdensome and will require significant additional man-hours.	

Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - Consumers Energy Company - 1,3,4,5 - RF	
Answer	
Document Name	
Comment	
No comment of opinion on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC	
Answer	
Document Name	
Comment	
Section 2.1.4 – Capitalize “c” in Planning coordinator Section 2.4.5 – delete “Based upon this assessment” at the beginning of the second sentence to be consistent with R2.1.5	
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	
Brandon Gleason - Electric Reliability Council of Texas, Inc. - 2, Group Name ISO/RTO Standards Review Committee	
Answer	
Document Name	
Comment	
No response.	
Likes 0	
Dislikes 0	
Response	

Additional comments received from Mike Smith - Manitoba Hydro (via attachment link in the comment report)

MH recommends the following changes to the footnote 13 of Table 1 (new text in red, removed text in green strikeout).

b. A single communications system associated with protective functions, necessary for correct operation of a communication-aided protection scheme required for Normal Clearing (except a single communications system that is both monitored and reported at a Control Center shall ~~not~~ be considered ~~non-~~redundant);

c. A single station dc supply and it's DC distribution circuits associated with protective functions required for Normal Clearing (except a single station dc supply and it's DC distribution circuits that is both monitored and reported at a Control Center for both low voltage and open circuit shall ~~not~~ be considered ~~non-~~redundant);

d. A single ~~control~~ trip circuitry ~~(including auxiliary relays and lockout relays)~~ associated with protective functions, from the ~~dc supply~~ protection relay through and including the trip coil(s) of the circuit breakers or other interrupting devices required for Normal Clearing (except a single trip circuit and coil that is both monitored and reported at a Control Center shall ~~not~~ be considered ~~non-~~redundant).

e. A single auxiliary tripping or lockout relay associated with protection tripping;

Rationale:

In footnote-13c, it is not clear whether or not monitoring is a satisfactory way to address only the SPF of the main supply (batteries and main bus) or also of the various branch circuits involved in DC distribution. The proposed changes allow for monitoring exceptions for DC Distribution and components of the trip circuit which are low probability items for failure similar to the previous exceptions permitted for DC supplies, communications and trip coils. We would also like to propose to put auxiliary trip relays and lockout relays on their own line to make it 100% clear that they must be considered in a SPF analysis.

Comments received from Jeremy Voll - Basin Electric Power Cooperative (via attachment link in the comment report)

Questions

1. With many clarifications added to the Technical Rationale concerning details of what is meant by Footnote 13, do you agree with the contents of Footnote 13?

☐ Yes

☒ No

Comments: Please consider the following:

Remove the double negative wording in 13.b, 13.c, and 13.d to make it clearer and less complicated with wording like, “shall be considered redundant”.

Add wording like, “Backup protection or a Composite Protection System is an acceptable alternative to a fully identical redundant protection if it provides acceptable System performance.” at the end of Footnote 13. A statement like this needs to be in the standard. Otherwise, it can be disregarded in an audit. In addition, replace the “Clarification: Is backup clearing redundant?” section on page 3 of the Technical Rationale with a different question and discussion like the following:

Clarification: “When is backup protection or a Composite Protection System acceptable as an alternative to fully identical redundant protection?”

If backup protection or a Composite Protection System (defined in PRC-004) provides acceptable System performance when a component of the primary Protection System fails, then fully identical redundant protection is unnecessary. Backup protection or a Composite Protection System may result in delayed clearing in comparison to a primary Protection System and trip additional Elements (refer to the NERC definition of Delayed Clearing and Normal Clearing Times). However, if any of these protection alternatives result is acceptable System performance, then fully identical redundant protection is unnecessary. If one of these protection alternatives already exist, then no Corrective Action Plan is needed. Or if one of these protection alternatives is effective, then it could be used as a suitable Corrective Action Plan in lieu of a fully identical redundant Protection System.

The terms and application of the terms in Footnote 13 do not appear to be consistent with those used in PRC-004 standard and the definition of Delayed Clearing and Normal Clearing Times in the NERC Glossy of Terms. The wording in the standard and the Technical Rationale should include and discuss the terms, Delayed Clearing and Normal Clearing Times and Composite Protection System and be consistent with them.

Add other statements at the end of Footnote 13 to clarify and confirm key matters in the TPL-001 standard so that it cannot be disregarded in an audit. The proposed wording for these statements are the following:

- “Voltage and current sensing devices of a Protection System are not considered.” Discussion of this matter is only in the Technical Rationale (p. 4) right now.
- “Protective relays (such as sudden pressure relays or thermal temperature relays) that do not respond to electrical quantities shall not be considered redundant”. Discussion of this matter is only in the Technical Rationale (p. 5) right now
- “The reclosing relays of a Protection System are not considered.” This matter is not presently discussed in the Technical Rationale.
- “Two communication systems must use separate communication paths (e.g. not be the same power line carrier line, same OPGW, same microwave tower, or same tone path, etc.) to be considered redundant. A SONET ring shall be considered redundant.” This matter is not presently discussed in the Technical Rationale.
- “Control circuitry includes everything from the DC supply through and including the trip coils, as well as auxiliary and lockout relays. A trip coils with monitoring do not need to be redundant.” This matter is not presently discussed in the Technical Rationale.

Remove the single communication system exemption when a system is monitored and reported to a Control Center. This exemption exposes Transmission Operators (TOPs) to potential noncompliance with TOP-001 (and TOP-002 if the communication failure condition continues into the next operating day). In the real time environment, TOPs must respond to the loss of communication until that pathway is repaired. Under the definition of Real Time Assessment, which is used in TOP-001, TOPs must operate within all SOLs for the topology that exists at that moment, which explicitly includes the status of protection systems. With the loss of protective function communication, the delayed clearing due to a SLG fault could cause an unacceptable system stability performance deficiency. TOPs do not have real-time stability analysis tools to keep checking pre-contingency for potential unacceptable system stability and appropriate new/temporary SOLs. Removal of the exemption would result in planning horizon analysis of non-redundant communication failures and corrective actions when unacceptable stability performance is found. Therefore, removal of the exemption would reduce the risk of TOPs being noncompliant with TOP-001 and TOP-002.

2. Do you agree with the removal of Requirement 1, Part 1.1.2 and changes to TPL-001-4 Requirement 2, Parts 2.1.4 and 2.4.4, in order to meet the FERC directive in Order No. 786?

   ☒ Yes

   ☐ No

   Comments:

   The revisions appear to address both the FERC and industry issues and concerns.

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

   ☒ Yes

   ☐ No

   Comments:

4. Do you agree with the proposed implementation plan?

   ☐ Yes

   ☒ No

   Comments:

   It would be better for the first timeframe to be 4 or 5 years, rather than 3 years, from FERC approval of TPL-001-5 to make the model changes, develop the new contingency files, perform the additional analysis, and developing CAPs for non-P5 contingency system deficiencies. The second timeframe of 2 years and third timeframe of 4 years to complete the other required tasks seem acceptable.

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. 754 and Order No. 786?

   ☐ Yes

   ☒ No

   Comments:

See comments in Question 1 regarding the acceptability of backup protection or Composite Protection System if they provide acceptable System performance. It is not cost effective to require the costlier installation of fully identical redundant primary protection when the primary protection happens to be faster and trip fewer Elements than acceptable backup protection or a Composite Protection System.

It is unclear what evidence would be sufficient to demonstrate compliance with Footnote 13. An onerousFor example, the assembly of sufficient evidence of redundant control circuitry for an audit may involve the compilation of hundreds of station schematic drawings, wiring drawings, and photos, beside description documents that may be needed to explain the substation evidence. Sufficient evidence to demonstrate redundant communications and DC supplies may be similarly burdensome.

Comments received from Chris Scanlon – Exelon (via attachment link in the comment report)

Questions

1. With many clarifications added to the Technical Rationale concerning details of what is meant by Footnote 13, do you agree with the contents of Footnote 13?

☐ Yes

☒ No

Comments: For clarity of purpose the double-negatives should be removed from 13b, 13c, and 13d. Consider: "…*that is both monitored and reported at a Control Center shall ~~not~~ be considered ~~non-~~redundant)"*