Comment Report

Project Name:	2023-06 CIP-014 Risk Assessment Refinement | Draft 1
Comment Period Start Date:	5/20/2024
Comment Period End Date:	7/3/2024
Associated Ballots:	Project 2023-06 CIP-014 Risk Assessment Refinement CIP-014-4 | Non-Binding Poll IN 1 NB Project 2023-06 CIP-014 Risk Assessment Refinement CIP-014-4 IN 1 ST Project 2023-06 CIP-014 Risk Assessment Refinement Implementation Plan IN 1 OT

There were 75 sets of responses, including comments from approximately 176 different people from approximately 102 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the modification in “Applicability” by moving 4.1.1 to Attachent1?

2. Do you agree with the modifications made in CIP-014-4 with modified Requirement R1 to address the issues identified in the SAR?

3. Do you agree with the modifications made in CIP-014-4 with new Requirement R2 to address the issues identified in the SAR?

4. Do you agree with the modifications made in CIP-014-4 with new Requirement R3 to address the issues identified in the SAR?

5. Do you agree with the modifications made in CIP-014-4 with new Requirement R4 to address the issues identified in the SAR?

6. Do you agree with the modifications made in CIP-014-4 with adding Requirement R5 to address the issues identified in the SAR?

7. Do you agree with the Implementation Plan for CIP-014-4?

8. Do you agree that CIP-014-4 is cost effective to address the reliability issue of physical security? If no, why not?

9. Provide any additional comments for the standard drafting team to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Preformance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Jaimin Patal	Saskatchewan Power Coporation (SPC)	1	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities-Kansas (BPU)	1,3,5,6	MRO
					Peter Brown	Invenergy	5,6	MRO

					Angela Wheat	Southwestern Power Administration	1	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
Public Utility District No. 1 of Chelan County	Anne Kronshage	6		Public Utility District No. 1 of Chelan County - Voting Group	Anne Kronshage	Public Utility District No. 1 of Chelan County	6	WECC
					Diane Landry	Public Utility District No. 1 of Chelan County	1	WECC
					Rebecca Zahler	Public Utility District No. 1 of Chelan County	5	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
Tennessee Valley Authority	Brian Millard	1,3,5,6	SERC	TVA RBB	Ian Grant	Tennessee Valley Authority	3	SERC
					David Plumb	Tennessee Valley Authority	1	SERC
					Armando Rodriguez	Tennessee Valley Authority	6	SERC
					Nehtisha Rollis	Tennessee Valley Authority	5	SERC
Santee Cooper	Chris Wagner	1		Santee Cooper	John Abrams	Santee Cooper	1,3,5,6	SERC
					Weijian Cong	Santee Cooper	1,3,5,6	SERC
					Rene' Free	Santee Cooper	1,3,5,6	SERC
					Stephen Lowe	Santee Cooper	1,3,5,6	SERC
					Christie Pope	Santee Cooper	1,3,5,6	SERC
Exelon		1		Exelon	Daniel Gacek	Exelon	1	RF

	Daniel Gacek				Kinte Whitehead	Exelon	3	RF
Manitoba Hydro	Jay Sethi	1,3,5,6	MRO	Manitoba Hydro Group	Nazra Gladu	Manitoba Hydro	1	MRO
					Mike Smith	Manitoba Hydro	3	MRO
					Kristy-Lee Young	Manitoba Hydro	5	MRO
					Kelly Bertholet	Manitoba Hydro	6	MRO
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					John Nierenberg	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Jennifer Bray	Arizona Electric Power Cooperative, Inc.	1	WECC
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF

					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Austin Energy	Michael Dillard	5		Austin Energy	Michael Dillard	Austin Energy	5	Texas RE
					Lovita Griffin	Austin Energy	3	Texas RE
					Tony Hua	Austin Energy	4	Texas RE
					Imane Mrini	Austin Energy	6	Texas RE
					Thomas Standifur	Austin Energy	1	Texas RE
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Micah Runner	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					Dermot Smyth	Con Ed - Consolidated	1	NPCC

	Edison Co. of New York		
David Burke	Orange and Rockland	3	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
David Kwan	Ontario Power Generation	4	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
Sean Cavote	PSEG	4	NPCC
Jason Chandler	Con Edison	5	NPCC
Tracy MacNicoll	Utility Services	5	NPCC
Shivaz Chopra	New York Power Authority	6	NPCC
Vijay Puran	New York State Department of Public Service	6	NPCC
David Kiguel	Independent	7	NPCC
Joel Charlebois	AESI	7	NPCC
Joshua London	Eversource Energy	1	NPCC
Nicolas Turcotte	Hydro-Quebec (HQ)	1	NPCC
Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
Joel Charlebois	AESI	7	NPCC
John Hastings	National Grid	1	NPCC
Erin Wilson	NB Power	1	NPCC

					James Grant	NYISO	2	NPCC
					Michael Couchesne	ISO-NE	2	NPCC
					Kurtis Chong	IESO	2	NPCC
					Michele Pagano	Con Edison	4	NPCC
					Bendong Sun	Bruce Power	4	NPCC
					Carvers Powers	Utility Services	5	NPCC
					Wes Yeomans	NYSRC	7	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Curtis Crews	WECC	10	WECC
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of	1	WECC

						Northern California		

1. Do you agree with the modification in "Applicability" by moving 4.1.1 to Attachent1?

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
Moving "Applicability" is acceptable. But new addition of Applicability 2.1 needs further clarification on physical adjacency in the Applicability. Would like clarification on applicability, does any station below 200kV need to be included in proximity check? Ties in with R2.	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation recommends leaving "Applicability" in 4.1.1 and not creating an "Attachment 1" as it does not follow the flow of most Standards currently in use and may cause confusion.	
Likes 0	
Dislikes 0	
Response	
Matt Carden - Southern Company - Southern Company Services, Inc. - 1	
Answer	No
Document Name	
Comment	
Southern Company disagrees with the inclusion of Attachment 1 (2.1) in the proposed standard. Requirement R2 addresses the need to provide clear expectations regarding the inclusion of physically adjacent elements in the risk assessment. However, the SAR did not identify a need to modify applicability.	
Likes 0	

Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	

Changing the Functional Entity description and moving it to Attachment 1, then requiring each TO to maintain a list of facilities identified in Attachment 1 complicates compliance for smaller TOs. Specifically, smaller TOs which do not operate facilities listed in Attachment 1 must maintain null lists and represents a compliance risk due to the administration of these lists. During compliance audits, auditors will use subjective judgement as to how the lists should look, how frequently they should be updated/reviewed/maintained, and who is ultimately responsible in the organization to ensure that they are correct. Entities will be expected to have multiple compliance controls in place to ensure the null lists are created, reviewed, approved and properly managed. During compliance audits R1, in relation to the movement of the Functional Entity description, will result in zero defect compliance. Entities will have risks related to the fact that they didn't feel a null list is appropriate and necessary to verify they have no assets that qualify under this standard.

The movement of the Functional Entity description further complicates compliance whereby the entity now must dig through the standard to determine its applicability, rather than simply looking at the Applicability Section of the standard.

Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	

Tacoma Power supports the MRO NSRF comments, as follows.

The MRO NSRF agrees with moving the Applicability criteria into an Attachment 1.

However, the MRO NSRF recommends removing Criterion 2.1 from Attachment 1. The Project 2023-06 SAR asked to revise the risk assessment to account for adjacent substations, but did not ask for changes to the applicable Facilities. Further, the NERC Report titled, "Evaluation of the Physical Security Reliability Standard and Physical Security Attacks to the Bulk-Power System," concluded that "…based on available data, the Applicability criteria in Reliability Standard CIP-014-3 appears to adequately identify the subset of all transmission stations and substations that TOs should evaluate as part of the Requirement R1 risk assessments."

In addition, Criterion 2.1 creates a scenario whereby one entity could identify that it has an applicable substation when considered in aggregate with a different entity's substation down the street. That other entity may have different proximity criteria and therefore not consider its substation applicable, when the intent, as drafted, appears to be that both substations would be considered applicable.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	

Comment

The MRO NSRF agrees with moving the Applicability criteria into an Attachment 1.

However, the MRO NSRF recommends removing Criterion 2.1 from Attachment 1. The Project 2023-06 SAR asked to revise the risk assessment to account for adjacent substations, but did not ask for changes to the applicable Facilities. Further, the NERC Report titled, “Evaluation of the Physical Security Reliability Standard and Physical Security Attacks to the Bulk-Power System,” concluded that “…based on available data, the Applicability criteria in Reliability Standard CIP-014-3 appears to adequately identify the subset of all transmission stations and substations that TOs should evaluate as part of the Requirement R1 risk assessments.”

In addition, Criterion 2.1 creates a scenario whereby one entity could identify that it has an applicable substation when considered in aggregate with a different entity’s substation down the street. That other entity may have different proximity criteria and therefore not consider its substation applicable, when the intent, as drafted, appears to be that both substations would be considered applicable.

Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	

Response

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB

Answer	No
Document Name	

Comment

TVA disagrees with the modifications to the “Applicability” section based on the changes made to criterion 2.1 in Attachment 1. TVA has two fundamental disagreements with this criterion:

1. Nonapplicable facilities should remain nonapplicable and not be subject evaluation in aggregate based on physical location or the other criteria outlined in R2. No evidence or basis in fact is provided to justify an event type that would trigger the consideration of two (2) individual facilities as a single facility.
2. TVA also disagrees with the changes to R2, on which aggregate facility evaluation is based, with the belief that additional clarification is required on the definition and application of “proximity”.

The requirement to evaluate facilities for applicability in aggregate should be removed from the standard or additional clarifications to R2 should be provided as outlined by TVA.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Insitute (EEI) and MRO NSRF for question #1.

Likes 0	
Dislikes 0	

Response

Leshel Hutchings - AEP - 3

Answer	No
Document Name	

Comment

We are not opposed to the Applicability section moving to 4.1.1 to Attachment 1, however additional changes were made to the Applicability section which should be stricken.

Bullet 2.1 "*Transmission station(s) or Transmission substation(s), that individually are not applicable, but are applicable when combined based on physical adjacency per Requirement R2, based on aggregated weighting value criteria from Table 1 are to be considered as applicable*" should be entirely removed. The content of the Applicability section should be unchanged with this SAR, which has a focused scope on the R1 risk assessment.

Bullet 2.1 would add excessive compliance burden, for both large and small TOs, while explicitly targeting an incredibly small risk. Previously, applicability scoring could be done first. Then small TOs with no applicable stations did not have to proceed with burdensome, manual, or time-consuming evaluations of proximity at all. Large TOs could proceed with detailed evaluations of proximity on the smaller applicable list. 2.1 would require a proximity screening to be performed on every 200 kV+ station on an entity's footprint to even determine the applicable list. This also opens the door for an auditor who takes issue with an entity's technical rationale for proximity to take issue with the entire applicability list.

Additionally, Applicability Section 4.1.1.1 through 4.1.1.4 mirror those Transmission Facilities that meet the bright line criteria for "Medium Impact" Transmission Facilities under Attachment 1 of Reliability Standard CIP-002- 5.1. Modifying the Applicability section would cause unnecessary inconsistency between these aligned standards.

Likes 0	
Dislikes 0	

Response
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment
BPA believes it is less of a compliance documentation burden for Registered Entities to determine exemption at the Section 4 level versus complying with R1, and having to document that compliance, in order to determine the rest of the requirements do not apply. BPA understands the original intent of CIP-014 was to identify a very small number of the absolutely most critical substations. BPA asserts that requiring Registered Entities to go through the R1 exercise in order to determine they are exempt is contrary to the original intent of the standard.

Likes 0	
Dislikes 0	

Response
Karen Demos - NextEra Energy - Florida Power and Light Co. - 3

Answer	No
Document Name	

Comment
NextEra/FPL supports EEI's comments

Likes 0	
Dislikes 0	

Response
Ben Hammer - Western Area Power Administration - 1

Answer	No
Document Name	

Comment
WAPA agrees with moving the Applicability criteria into an Attachment 1. WAPA concurs with the comments provided by the MRO NSRF and the elimination of Criteria 2.1.

Likes 0	

Dislikes 0	
Response	
Michael Dillard - Austin Energy - 5, Group Name Austin Energy	
Answer	No
Document Name	MRO-Tacoma CIP-014 comments.docx
Comment	
Austin Energy supports MRO's comments.	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
NEE support's EEI comments: " EEI supports moving 4.1.1 to Attachment 1, however, we disagree with the inclusion of, and suggest striking, criterion 2.1 in the Applicability section because it is outside of the scope of the SAR. The SAR asks the drafting team to provide clear expectations regarding the inclusion of physically adjacent elements for the purpose of evaluating the impact from a physical attack, but it does not require or request modifications to the applicability of the Standard or requirements. Multiple non-applicable stations within reasonable proximity should not be deemed applicable when considered as a whole. It is the presence of an applicable station that requires evaluation of a physical attack and the identification of additional stations that may be impacted. Further, criterion 2.1 includes a circular reference to Requirement R2 for Transmission station(s) or Transmission substation(s) that individually are not applicable when CIP-014-4 Requirement R1, Part 1.3 states that if the TO identified no applicable Transmission station(s) or Transmission substation(s) they are not required to fulfill the remainder of the standard, including Requirement R2. "	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	

Comment	
Tri-State agrees with the MRO NSRF Submitted Comments	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
SMUD agrees with the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with moving 4.1.1 to Attachment 1. However, Black Hills Corporation aligns with EEI comments and disagrees with the inclusion of criterion 2.1 in the Applicability section as it creates a circular reference that brings in station(s)/substation(s) that are individually not applicable via Attachment 1, which is outside the scope of the SAR. Black Hills Corporation recommends striking criterion 2.1 from the Applicability section.	
Likes 0	
Dislikes 0	
Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	No

Document Name	
Comment	

Duke Energy supports EEI comments that disagree with the inclusion of criterion 2.1 in Attachment 1 and suggests striking it.

Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	
Comment	

Dominion Energy supports EEI comments.

Likes 0	
Dislikes 0	
Response	

Andrew Smith - APS - Arizona Public Service Co. - 5

Answer	No
Document Name	
Comment	

AZPS supports moving 4.1.1 to Attachment 1, however agrees with EEI's comments which ask the SDT to provide clear expectations regarding the inclusion of physically adjacent elements for the purpose of evaluating the impact from a physical attack.

Likes 0	
Dislikes 0	
Response	

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	No
Document Name	
Comment	

Louisville Gas & Electric and Kentucky Utilities support EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP supports the MRO NSRF with Tacoma Power's comments.	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
Thank you for the chance to comment, SERC appreciates the complexity of the SDT's task of modifying multiple parts of such a high-profile and high-priority standard. · Item #Applicability.A: We agree that moving the Applicability to Attachment 1 is effective and accommodates the changes in the new R1 and R2. However, we encourage the SDT to add an additional Transmission Substation applicability criterion similar to the existing CIP-002-5.1a Attachment 1 Criterion 2.8. Specifically, to add CIP-014-3 substation applicability for any Transmission substation/station which connects an aggregate of 1500MW or more generation to the BES. This stems from a field observation that it is not abnormal for substations below the 499-200kV thresholds (which don't meet the line count to be included under CIP-014-4 Attachment 1, Criterion 2) to demonstrate stability impacts. Perhaps a field trial could identify the validity of their inclusion and if such a reliability gap exists.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	

Answer	No
Document Name	
Comment	

Minnesota Power supports MRO-NSRF and EEI's comments.

Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	

Ameren supports EEI's comments on this project.

Likes 0	
Dislikes 0	
Response	

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI supports moving 4.1.1 to Attachment 1, however, we disagree with the inclusion of, and suggest striking, criterion 2.1 in the Applicability section because it is outside of the scope of the SAR. The SAR asks the drafting team to provide clear expectations regarding the inclusion of physically adjacent elements for the purpose of evaluating the impact from a physical attack, but it does not require or request modifications to the applicability of the Standard or requirements. Multiple non-applicable stations within reasonable proximity should not be deemed applicable when considered as a whole. It is the presence of an applicable station that requires evaluation of a physical attack and the identification of additional stations that may be impacted.

Further, criterion 2.1 includes a circular reference to Requirement R2 for Transmission station(s) or Transmission substation(s) that individually are not applicable when CIP-014-4 Requirement R1, Part 1.3 states that if the TO identified no applicable Transmission station(s) or Transmission substation(s) they are not required to fulfill the remainder of the standard, including Requirement R2.

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	

Comment

Modifying the Applicability section to move 4.1.1 to Attachment 1 is not a substantive change and is not particularly problematic.

Criteria 2.1 in the proposed attachment is not clearly worded and doesn't appear necessary as R2 is fairly clear on the applicability of proximity facilities. If this criteria is retained in the attachment, it should be simplified to simply refer to R2 and remove the additional unnecessary language.

(Regarding Criteria 3) Additionally, with the retirement of FAC-010, planning entities do not establish SOLs under the NERC standards. This criteria correctly refers to IROLs established by the RC but the language around the planning entities needs to be updated to correspond with the language established by NERC Project 2015-09 regarding the PC/TP identifying instances of "instability, Cascading or uncontrolled separation that adversely impacts the reliability of the BES."

Likes 0	
Dislikes 0	

Response

Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	No
Document Name	

Comment

IID agrees with transferring the applicability criteria from Section 4.1.1 to Attachment 1.

IID does not agree with the addition of the language in Criterion 2.1. This addition will complicate compliance for "adjacent" facilities owned by different entities.

A small entity may not have any stations subject to CIP-014, but it may be adjacent to a large transmission facility of another entity that falls under CIP-014. These stations would be verified through duplicative R2 criteria, resulting in the performance of a risk assessment under R5. The small entity conducting the risk assessment may end up with a list of stations that it neither owns nor operates.

What implications does this have for compliance with CIP-014? How should the small entity proceed to adhere to R6-R10? Will the small entity be tasked with assessing threats and vulnerabilities of the large transmission facilities that they neither own or operate? Furthermore, would they be responsible implementing security measures for these stations as well?

Likes 0	
Dislikes 0	

Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	

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Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	

See comments submitted by the Edison Eclectic Institute

Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

NV Energy supports the EEI response to this question.

Likes 0	
Dislikes 0	

Response

Carver Powers - Utility Services, Inc. - 4

Answer	No
Document Name	

Comment

The proposed changes of moving the applicability of the standard to R1 and Attachment 1 now brings low impact entities into scope. Is this the intent of the Standard Drafting Team? Is the intent of this modification to require low impact entities to consider the criteria in Attachment 1? This process is already being completed by entities during their CIP-002 BES Cyber System categorization.

Likes 0	
Dislikes 0	

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

See EEI comments

Likes 0	
Dislikes 0	

Response

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott

Answer	No
Document Name	

Comment

ITC supports the EEI response

Likes 0	
Dislikes 0	

Response

Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
Answer	No
Document Name	

Comment

PNM and TNMP support EEI comments regarding 4.1.1, noted again here.

"EEI supports moving 4.1.1 to Attachment 1, however, we disagree with the inclusion of, and suggest striking, criterion 2.1 in the Applicability section because it is outside of the scope of the SAR. The SAR asks the drafting team to provide clear expectations regarding the inclusion of physically adjacent elements for the purpose of evaluating the impact from a physical attack, but it does not require or request modifications to the applicability of the Standard or requirements. Multiple non-applicable stations within reasonable proximity should not be deemed applicable when considered as a whole. It is the presence of an applicable station that requires evaluation of a physical attack and the identification of additional stations that may be impacted.

Further, criterion 2.1 includes a circular reference to Requirement R2 for Transmission station(s) or Transmission substation(s) that individually are not applicable when CIP-014-4 Requirement R1, Part 1.3 states that if the TO identified no applicable Transmission station(s) or Transmission substation(s) they are not required to fulfill the remainder of the standard, including Requirement R2. "

Likes 0	
Dislikes 0	

Response

Jason Snodgrass - Jason Snodgrass On Behalf of: Katrina Lyons, Georgia System Operations Corporation, 3, 4; - Jason Snodgrass	
Answer	No
Document Name	

Comment

GSOC supports comments provided by Georgia Transmission

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no objection.	
Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
AEPC signed on to ACES comments below: ACES agrees with moving the Applicability to Attachment 1. While ACES agrees with the question asked, Criterion 2.1 from Attachment 1 is beyond the scope of the SAR. Further, Criterion 2.1 could create a situation where one entity identifies an Applicable substation when considered with another adjacent entity's substation. The other entity may have a different proximity criteria and not considered an Applicable substation when both should be applicable.	
Likes 0	
Dislikes 0	
Response	

Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Eversource agrees with the creation of Attachment 1 but offers some minor comments: **2.1:** For sake of consistency, the phrase "physical adjacency" should be removed from section 2.1 and replaced with "proximity" to better align with R2. - The "500 kV and above" section should either be removed from the table in its entirety due to confusion being listed as zero, or replace the zero with a phrase like "must be studied." Phrases ("not applicable") are already being used within the table so it would be a similar approach.	

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	
MPC concurs with ACES' comments regarding Criterion 2.1 of Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Exelon supports moving the Applicability criteria into Attachment 1. Exelon interprets the SAR to require the assessment of a physical attacks on physically adjacent elements, and therefore supports the intent of Attachment 1, Section 2.1 and the R2.1 criteria to identify substations that are to be combined and treated as a single substation site for the purpose of the risk assessment The Attachment 1, Section 2.1, reference to the R2 methodology is confusing. Consider removing the reference to R2 and including physical adjacency criteria within Section 2.1; or alternatively, consider combining R1 and R2 and moving the Section 2.1 process step into R2.	
Likes 0	
Dislikes 0	
Response	
Chris Shultz - Seattle City Light - 5	
Answer	Yes
Document Name	

Comment	
Moving the substation applicability criteria into the attachment (and referencing it from R1) makes sense.	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	
Moving the substation applicability criteria into the attachment (and referencing it from R1) makes sense.	
Likes 0	
Dislikes 0	
Response	
Zenon O'young-Chu - Seattle City Light - 3	
Answer	Yes
Document Name	
Comment	
Moving the substation applicability criteria into the attachment (and referencing it from R1) makes sense.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	

WECC voted affirmative for the proposed standard but offers the following for serious consideration by the drafting team.

Placement within Attachment 1 versus in 4.1.1 is appropriate. However, the inconsistent use of “Transmission station”, “Transmission substation”, “Transmission Facilities”, “station”, “substation” does not support clarity. The first sentence of Attachment 1 is “Applicable Transmission station(s) or Transmission substation(s) that meet any of the following criteria:”. The second criterion starts with “Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation…” Why not consider changing Transmission Facility usages to Transmission station and Transmission substation? Example- “1. Transmission station(s) and Transmission substation(s) operated between 200 kV and 499 kV, where the Transmission station or Transmission substation is connected….” Criterion 2.1 illustrates that approach.

Attachment 1 needs to address consideration of the Transmission station(s) and Transmission substation(s) without regards to joint/multiple/shared ownership. Requirement 4 will determine which entity does the risk assessment but Transmission Owners should maintain the list inclusive of these arrangements. Responsibility could change in terms of performing the assessment.

Criterion 2.1 uses “adjacency” versus “proximity”. Consider changing that to read “Transmission station(s) or Transmission substation(s) that individually are not applicable based on the aggregated weighting value criteria from Table 1 but are applicable when included in the risk assessment based on proximity criterion per Requirement R2.” Suggest labeling Table 1. Suggest clarifying Table 1 to ensure that a Transmission station(s) or Transmission substation(s) in close proximity are applicable to use in the assessment regardless of voltage level or alternatively if operated between 200 kV and 499 kV. Example- Is there clarity in this scenario: A 345 kV line (one of three from the CIP-014-4 applicable substation X) connects to substation Y which is in the “line-of-site” and steps down to 138 kV with multiple Transmission Lines connecting other Transmission substation(s). Substation Y is included not considering the weighting criteria as applied at substation Y or does substation Y have to consider the weighting criteria to be included in the assessment?

And just to be clear, any Transmission station or substation that has a single 500 kV or above Transmission Line is included, correct?

Criterion 3 should be reviewed and updated to reflect Project 2015-09 language regarding IROLs applicability to the Planning Coordinator and Transmission Planner. Also- it is unclear who the “its” is referencing to a certain degree. Consider this option: “3. Transmission station(s) or Transmission substation(s) that are identified by a Transmission Owner’s Reliability Coordinator as critical to the identification of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies. Transmission station(s) or Transmission substation(s) that are identified by a Transmission Owner’s Planning Coordinator(s) and Transmission Planner(s) as associated with identified instability.” See FAC-014-3 from Project 2015-09. A voltage limitation could be included to drive consistency—i.e. after “Transmission substation(s)” in the suggested option add “operated at 200 kV and above”.

Criterion 4 refers back, essentially, to NUC-001 which does not capitalize Facilities in Requirement 9 Part 9.2.2. This is yet another reason to consider Transmission station(s) and Transmission substation(s) instead of Transmission Facilities. Should this Criterion also consider Contingencies associated with the Transmission substation(s) and Transmission station(s) identified as “essential for meeting the NPIRs”?

Just to be clear, this criteria includes underground Transmission station(s) and Transmission substation(s), correct?

Consider inclusion of criteria for levels of generation within a substation or substations within the proximity determined. Simply looking at Transmission overlooks a significant risk as Transmission substations can be rebuilt quickly when compared to rebuilding or fixing a set of generators.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	

Comment	
ACES agrees with moving the Applicability to Attachment 1. While ACES agrees with the question asked, Criterion 2.1 from Attachment 1 is beyond the scope of the SAR. Further, Criterion 2.1 could create a situation where one entity identifies an Applicable substation when considered with another adjacent entity's substation. The other entity may have a different proximity criteria and not considered an Applicable substation when both should be applicable.	
Likes 0	
Dislikes 0	
Response	

Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rebika Yitna - Rebika Yitna On Behalf of: Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO, Group Name Manitoba Hydro Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelley Sargent - Puget Sound Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lucinda Bradshaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1 - RF	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tyler Schwendiman - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fon Hiew - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - James Baldwin On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - James Baldwin	
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 NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jang - Seattle City Light - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Daren Brubaker - Seattle City Light - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

2. Do you agree with the modifications made in CIP-014-4 with modified Requirement R1 to address the issues identified in the SAR?	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
ACES agrees with the changes, but recommends changing Attachment 1 to remove the reference to R2. This allows R1 and R2 to standalone leaving R1 for the identification of applicability and R2 for proximity criteria.	
Likes 0	
Dislikes 0	
Response	
Jason Snodgrass - Jason Snodgrass On Behalf of: Katrina Lyons, Georgia System Operations Corporation, 3, 4; - Jason Snodgrass	
Answer	No
Document Name	
Comment	
GSOC supports comments provided by Georgia Transmission	
Likes 0	
Dislikes 0	
Response	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
Answer	No
Document Name	CIP-014-4 Draft 1, Question 2 PNM_TNMP response.docx
Comment	
PNM and TNMP support EEI comments regarding R1, noted again here. Additionally, please see **document attached** in this question response. PNM and TNMP offer additional comments and illustrative diagram for SDT consideration. *"EEI proposes the following modifications:* *Add 'calendar' to Requirement R1, Part 1.2 to ensure that entities continue to have the same flexibility afforded to them under CIP-014-3 to align with calendar months instead of specific dates:*	

1.2 Review the list every 36 ***calendar*** *months and update the list, if necessary.*

Suggest changing the text of R1.3 to read as follows:

If the Transmission Owner identifies no applicable Transmission station(s) and ***or*** *Transmission substation(s), then no additional actions are required to fulfill the remainder of the standard."*

Likes 0	
Dislikes 0	

Response

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott

Answer	No
Document Name	

Comment

ITC supports the EEI response

Likes 0	
Dislikes 0	

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

See EEI comments

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

NV Energy supports the EEI response to this question.

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Eclectic Institute	
Likes 0	
Dislikes 0	

Response

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	
The concept of the risk assessment in the currently approved standard and this draft is ambiguous and is interpreted differently across the industry. The standard requirements need additional clarification as to what type of risk (explosive, gunshot, etc) the TO should be protecting against. It is important to keep in mind that the clarification on the risk should take into account the premise that physical security measures may be installed pursuant to the assessment of this risk.	
Likes 0	
Dislikes 0	

Response

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI proposes the following modifications:

Add ‘calendar’ to Requirement R1, Part 1.2 to ensure that entities continue to have the same flexibility afforded to them under CIP-014-3 to align with calendar months instead of specific dates:

1.2 Review the list every 36 **calendar** months and update the list, if necessary.

Suggest changing the text of R1.3 to read as follows:

If the Transmission Owner identifies no applicable Transmission station(s) **or** Transmission substation(s), no additional actions are required to fulfill the remainder of the standard.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	

Comment

Ameren supports EEI's comments on this project.

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	

Comment

Minnesota Power supports MRO-NSRF and EEI's 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	
MPC concurs with the MRO NSRF's comments regarding combining R1 and R2. MPC strongly disagrees with the use of a 36 month timeframe for utilities who have not previously identified stations or substations as critical for the same reasons specified in our comments for question 6.	
Likes 0	
Dislikes 0	
Response	

Mark Flanary - Midwest Reliability Organization - 10	
Answer	No
Document Name	
Comment	
MRO is supportive of the proposed timeframe, however the language of R1.2 indicating "every 36 months" is unnecessarily strict. Consider softening to "at least every 36 months" or something similar that drives towards performance with a frequency no greater than every 36 months.	
Likes 0	
Dislikes 0	
Response	

Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	

Thank you for the chance to comment, SERC appreciates the complexity of the SDT's task of modifying multiple parts of such a high profile and high-priority standard.

· Item #1.A: R1 seems to be missing a key item from the SAR, under Detailed Description #2: "Revisions to the risk assessment should be made to only include transmission and generation projects that are appropriate to the periodicity of the entity's risk assessments. " This precept goes to both applicability and model accuracy, but is key that notional/planned transmission improvements that may be implemented beyond the 36 month study period are not considered. Planned transmission projects outside that 36 month time horizon could possibly be considered for Resiliency measures in R9.1.

· Item #1.B: The previous CIP-014-3 R1 requirement did not address applicability separately, and thus implied the applicable list of stations to be studied would be up-to-date and accurate as of the date of performance of CIP-014-3 R1 upon its 30 or 60 month cycle. However, now that R1 and R5 are separate requirements, an issue of accuracy or fidelity could emerge if R1 (which is now an untimed/undated requirement) was performed too many months/years prior to the performance of R5. This could result in a R1 (and downstream R2) list that was accurate at the time of preparation, but 'stale' by the time of R5 performance. The SAR seems to address this under Detailed Description Item #2: "Revisions to the risk assessment should be made to only include transmission and generation projects that are appropriate to the periodicity of the entity's risk assessments." as well as in the SAR Project Scope #2's reference of correction of discrepancies. We would suggest either introducing a timing component to R1 to ensure fidelity, or a accuracy component to R5 to ensure the R1 (and downstream R2) lists used are still accurate as of the time of the dated completion of R5.

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez

Answer	No
Document Name	

Comment

SRP supports the MRO NSRF with Tacoma Power's comments.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

Louisville Gas & Electric and Kentucky Utilities support EEI's comments.

Likes 0	
Dislikes 0	

Response

Andrew Smith - APS - Arizona Public Service Co. - 5

Answer	No
Document Name	

Comment	
AZPS supports EEI's proposal to utilize "calendar" months in R1.	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	No
Document Name	

Comment

Eversource is looking for clarity on what is meant by the phrase "planned to be" in service.

Requirement R1.2 also seems unnecessary. With the defined time period in R1.1 and the risk assessment cycle defined by R5, Eversource recommends the removal of R1.2 for brevity and clarity.

Eversource also believes that R1 should be solely about developing a list whereas R2 should define the stations that need to be included. See below for a proposed modification moving parts of R1 into R2.

R1. Each Transmission Owner shall establish and maintain a list of applicable Transmission

station(s) and Transmission substation(s) for performing risk assessments in

accordance with the criteria in Attachment 1. Each Transmission Owner shall:

[Violation Risk Factor: High; Time-Horizon: Long-term Planning]

1.1. Consider all Transmission station(s) and Transmission substation(s) that are

existing or planned to be in service within 36 months; and

1.2. Review the list every 36 months and update the list, if necessary.

1.3. If the Transmission Owner identifies no applicable Transmission station(s) and Transmission substation(s), then no additional actions are required to fulfill the remainder of the standard

R2. Each Transmission Owner shall establish and implement documented criteria for identifying Transmission station(s) and Transmission substation(s) **in accordance with Attachment 1, as well as stations in proximity to those identified through Attachment 1**, irrespective of ownership, that shall be included in the risk assessment. . *[Violation Risk Factor: Medium; Time-Horizon: Long-term*

Planning]

2.1. The criteria shall at a minimum include the following:

2.1.1. Line-of-sight between multiple Transmission station or Transmission

substation yards from a single site.

2.1.2. Ease of access from a common public roadway that exists between

multiple Transmission station or Transmission substation yards.

2.1.3. The Transmission station or Transmission substation yards are in close

enough proximity that a single event can impact multiple Transmission

stations or Transmission substations.

2.2. If the Transmission Owner identifies no applicable Transmission station(s) and

Transmission substation(s), then no additional actions are required to fulfill the

remainder of the standard.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy supports EEI Comments.

In addition to EEI comments, Dominion Energy considers that 36 months for planned substations is not realistic based on delays due to construction, supply chain, outage planning and PJM planning horizons.

Dominion Energy has the same issue with R1.2 as 36 months is not realistic due to the uncertainty on actual system configuration changes.

Likes 0	
Dislikes 0	

Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy supports the revisions to clarify the timeline for the performance of R1 requirements but requests additional clarity if the 36-month timeframe starts from the time of the completion of the risk assessments. Duke Energy also supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with EEI comments and proposed modifications.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State agrees with the MRO NSRF Submitted Comments	
Likes 0	

Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	

NEE support's EEI comments: " EEI proposes the following modifications:

Add 'calendar' to Requirement R1, Part 1.2 to ensure that entities continue to have the same flexibility afforded to them under CIP-014-3 to align with calendar months instead of specific dates:

{C}1.2 Review the list every 36 **calendar** months and update the list, if necessary.

Suggest changing the text of R1.3 to read as follows:

If the Transmission Owner identifies no applicable Transmission station(s) and **or** Transmission substation(s), then no additional actions are required to fulfill the remainder of the standard. "

Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

AEPC signed on to ACES comments below:

ACES agrees with the changes, but recommends changing Attachment 1 to remove the reference to R2. This allows R1 and R2 to standalone leaving R1 for the identification of applicability and R2 for proximity criteria.

Likes 0	
Dislikes 0	

Response	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	No
Document Name	
Comment	

Comments: In the SAR, there were 5 objectives listed in the Project scope:

1. Clarify the risk assessment methods for studying instability, uncontrolled separation, and Cascading within an Interconnection. The methods should account for dynamic studies.

Adequately addressed.

2. Clarify the case(s) used for the risk assessment to be tailored to the Requirement R1 in-service window and correct any discrepancies between the study period, frequency of study, and the base case(s) a Transmission Owner uses.

Not adequately addressed – the study window is not clarified. This generally appears to be a study in the operations horizon, yet the 36 month proposed window is beyond the operations horizon. For applicability, a Transmission Operator may not have sufficient station information to perform its required assessment for a station that has not been constructed. Furthermore, for system changes that could occur within this 36 month window (such as station modifications to protection or bus design, or physical security changes such as hardening access or 'line of sight'), this proposal does not speak to which 'version' of the system state (present or future-36 months) is to be studied. For example, if a station is known to cause instability for a particular event, but has a Corrective Action Plan to be implemented within the year to mitigate that instability, is it appropriate to include the Corrective Action Plan in the assumptions of the study? In summary, these sorts of issues were not clarified in this new revision, and further clarification is requested.

3. Assure the adequacy and consistent implementation of technically supported justification for study decisions. Clarity should include specificity regarding the documentation, and usage of criteria to identify instability, uncontrolled separation, or Cascading within an Interconnection occur as part of a risk assessment.

Adequately addressed.

4. Clarify what study scenario(s) and other study assumptions are appropriate and reasonable considering the intent of CIP-014-3 and the potential range of issues during a physical attack. Simulations should incorporate the loss of station elements without the reliance on local system protection.

Adequately addressed.

5. Clarify how to account for adjacent Transmission stations or Transmission substations of differing ownership as well as for those Transmission stations or Transmission substations within line-of-sight to each other. *This was listed as an item to modify R1, but ended up being in the new proposed version's R2.*

Not adequately addressed – the term 'line-of-sight' is vague and ambiguous. This has not had much technical discussion to support inclusion in a regulatory standard. For example, if one were to hike to the top of a very tall mountain, there are multiple substations that are within 'line of sight', yet a common attack vector would not likely impact all the stations that could be seen. NERC's intent is more likely in the flavor of 'what's in the neighborhood' and trying to establish some sort of proximity rationale here, but line-of-sight is likely a wrong word choice to express this concept of adjacencies. Similarly, in the subsequent build-up of R2 in addressing proximity, 'Ease of access' (R2.1.2) and 'close proximity…that a single event could impact…' (R2.1.3) are equally vague without supporting examples of intent from NERC. Ease of access may be difficult for a vehicle, but quite easy for a drone, helicopter, or other aerial device, or if near water, a boat may easily access sites that are difficult for automobile. Similarly, the impact zone of a single event could be small if a low capacity home-made device, but quite large if a nuclear device. NERC's new proposed language is ambiguous on what is acceptable. While it is noted this is ultimately criteria to be determined by the Transmission Owner, the ambiguities could lead to disagreements between Transmission Owners and regulators and audit staff over adequacy, where the expectation of levels of adequacy is not defined in the standard nor discussed in the Technical Rationale. It is requested these topics be revisited in light of these considerations.

Likes 0	
Dislikes 0	

Response

Michael Dillard - Austin Energy - 5, Group Name Austin Energy

Answer	No
Document Name	

Comment

Austin Energy supports MRO's comments. Attached in Question 1.

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	No
Document Name	

Comment

WAPA concurs with the use of the 36 month timeframe in the draft R1.

WAPA recommends removing the circular reference to R2 in Attachment 1, and keep R1 strictly to determining the applicability list for study. Requirement R1.3 states that no further action is required if no applicable Transmission stations are identified, however, in order to complete this identification, then R2 must be completed. In addition, WAPA recommends the removal of Criterion 2.1 in Attachment 1, in accordance with comments submitted in Q1.

Likes 0	
Dislikes 0	

Response

Karen Demos - NextEra Energy - Florida Power and Light Co. - 3

Answer	No
Document Name	

Comment	
NextEra/FPL supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes the rewritten R1 seems to be intended to create auditable documentation of the same outcome that is already achieved when a Registered Entity evaluates the current Applicability section.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Insitute (EEI) and MRO NSRF for question #2.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	

The MRO NSRF concurs with the use of the 36 month timeframe in the draft R1. The MRO NSRF recommends removing the circular reference to R2 in Attachment 1, and keep R1 strictly to determining the applicability list for study. Requirement R1.3 states that no further action is required if no applicable Transmission stations are identified, however, in order to complete this identification, then R2 must be completed. In addition, the MRO NSRF recommends the removal of Criterion 2.1 in Attachment 1, in accordance with comments submitted in Q1.	
Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	No
Document Name	
Comment	
• CIP-014-4 R1 requires the Transmission Owner to "…establish and maintain a list of applicable Transmission station(s) and Transmission substation(s)…" while R1.1 specifies that it must consider station(s) that are "…existing or planned to be in service within 36 months…" The phrasing could be interpreted that the list must be updated continuously and not just when it is reviewed. Suggest that R1 be modified to state that: "Each Transmission Owner shall **have a list** of applicable…." And let R1.1 and R1.2 specify how it is updated. • NERC utilizes the term calendar months; suggest that R1.1 be reworded to use the term "…within 36 **calendar** months…" • In CIP-014-4 R1.2 the list review cadence is listed as "…every 36 months…" which is a very specific timeframe and hypothetically if the list is updated at 35 months it would not be in compliance. Suggest the phrasing be updated to: "Review the list **at least once every** 36 calendar months…" • The stations identified in R2 must be included in the assessment in R3 but there is no requirement to add them to the R1 list as this list is derived from only Attachment 1. Suggest that the wording be added to the standard requiring all stations included in the assessment to be added to the R1 list and are periodically reviewed/updated.	
Likes 0	
Dislikes 0	
Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	No
Document Name	
Comment	

Comment 1: CIP-014-4 R1 requires the Transmission Owner to "…establish and **maintain** a list of applicable Transmission station(s) and Transmission substation(s)…" while R1.1 specifies that it must consider station(s) that are "…existing or planned to be in service within 36 months…" The phrasing could be interpreted that the list must be updated continuously and not just when it is reviewed. Suggest that R1 be modified to state that:

"Each Transmission Owner shall have a list of applicable…." And let R1.1 and R1.2 specify how it is updated.

Comment 2: NERC utilizes the term calendar months; suggest that R1.1 be reworded to use the term "…within 36 calendar months…"

Comment 3: In CIP-014-4 R1.2 the list review cadence is listed as "…every 36 months…" which is a very specific timeframe and hypothetically if the list is updated at 35 months it would not be in compliance. Suggest the phrasing be updated to:

"Review the list at least once every 36 calendar months…"

Comment 4: The stations identified in R2 must be included in the assessment in R3 but there is no requirement to add them to the R1 list as this list is derived from only Attachment 1. Suggest that the wording be added to the standard requiring all stations included in the assessment to be added to the R1 list and are periodically reviewed/updated.

Likes 0	
Dislikes 0	

Response

Lucinda Bradshaw - Oncor Electric Delivery - 1 - Texas RE

Answer	No
Document Name	

Comment

Oncor does not agree with the use of 36 months because that time frame is beyond Oncor's accurate planning frame, particularly given the current large amount of growth in Oncor's service area. Oncor recommends no longer than 24 months be used.

Likes 0	
Dislikes 0	

Response

Kelley Sargent - Puget Sound Energy, Inc. - 3

Answer	No
Document Name	

Comment

We agree with the intent of CIP-014-4 to address issues identified in the SAR, however we would like to suggest changes to improve readability.
There is some interplay between R1 and R2 through Attachment 1 that makes identification of "applicable" stations confusing. R1 refers to Attachment 1

to identify “applicable” stations based on the weighting criteria in Table 1. Attachment 1 section 2.1 requires user to refer to R2 and apply proximity criteria to stations that were not applicable in R1.

To meet the intent of SAR to identify station “groups” that meet applicability criteria of Attachment 1, it may be best to identify station groups separately under R2 as a sub-requirement (i.e. move Section 2.1 from Attachment 1 to sub-requirement R2.2) and make Attachment 1 agnostic of stations or station groups. This separates intent of R1 and R2 and allows both requirements to reference Attachment 1 applicability criteria. R1 will identify individual stations that meet Attachment 1 applicability criteria. R2 will identify station groups with stations that were individually non-applicable under R1, but when combined with other non-applicable station(s) - based on proximity criteria of R2, may be applicable per Attachment 1 Table 1.

Likes 0	
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Tacoma Power supports the MRO NSRF comments, as follows.

The MRO NSRF concurs with the use of the 36 month timeframe in the draft R1.

The MRO NSRF recommends removing the circular reference to R2 in Attachment 1, and keep R1 strictly to determining the applicability list for study. Requirement R1.3 states that no further action is required if no applicable Transmission stations are identified, however, in order to complete this identification, then R2 must be completed. In addition, the MRO NSRF recommends the removal of Criterion 2.1 in Attachment 1, in accordance with comments submitted in Q1.

Likes 0	
Dislikes 0	

Response

Kevin Conway - Western Power Pool - 4

Answer	No
Document Name	

Comment

The CIP-014 modifications seem objective and responsive to the SAR, however a deeper reading of R2 and R3 indicate that the Drafting Team is allowing each entity the latitude for flexibility in it’s criteria and methodologies. This continues the inconsistencies in CIP-014 Risk Assessments between entities. “The requirement language within CIP-014-3 does not prescribe a specific method for how each risk assessment shall be performed.” (see

2023-06 CIP SAR 07262023 pg.2) The current proposal adds a list of items to be included, but falls short of the goal to ensure consistency between entities.	
Likes 0	
Dislikes 0	
Response	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1 - RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Maintaining a list is appropriate. Ensuring how the list is addressed within the assessment for each Transmission station and Transmission substation will be critical and indicates that assessments should be done sequentially/chronologically to effectively represent the configuration being assessed. Suggest adjusting language in Requirement R1.1 to "Include" versus "Consider". Also, later on in the Standard "calendar months" is used versus simply "months". Please consider adjusting for consistency all period descriptions to one or the other. For Requirement R1.3 consider: "If the Transmission Owner identifies no applicable Transmission station(s) and Transmission substation(s) using the criterion in Attachment 1, then document the condition accordingly." There may actually be actions required if a Transmission Owner having an applicable Transmission station or Transmission substation has a Transmission Line emanating from the applicable Transmission station/Transmission substation that terminates in a different Transmission Owner's Transmission station or Transmission substation meeting the criteria in Requirement R2. In turn, the two Transmission Owner's may need to coordinate actions as Requirement R4 states. SDT can provide the clarity needed as the condition exists and the second Transmission Owner may need to consider the loss of the proximity-based included Transmission station/substation in its own risk assessments. If the DT elects not to remove the phrase regarding "no additional actions", update "standard" to "reliability Standard" for consistency.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	

Answer	Yes
Document Name	
Comment	
Exelon supports the EEI comment to add "calendar" to the timeframe stated in 1.2.	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
While we agree that the modification meets the intent of the SAR, sub-requirement R1.2 should be modified to allow some flexibility in review timing. Change wording to "Review the list **at least** every 36 months and update the list, if necessary.	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	Yes
Document Name	
Comment	
TVA agrees with the modifications to R1, aligning facility in-service dates, list creation, and list review timelines 36 months. TVA again states an objection to the modified Applicability criteria, specifically to evaluate nonapplicable facilities in aggregate, per Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes

Document Name	
Comment	
FirstEnergy has no objection to the modifications made to R1.	
Likes 0	
Dislikes 0	
Response	
Tyler Schwendiman - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
For R1.1.2, is the verbiage “, if necessary” needed? The list should be reviewed every 36 months.	
Likes 0	
Dislikes 0	
Response	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO, Group Name Manitoba Hydro Group	
Answer	Yes
Document Name	
Comment	
Manitoba Hydro recommends removing the circular reference to R2 in Attachment 1. Requirement R1.3 states that no further action is required if no applicable Transmission stations are identified, however, in order to complete this identification, R2 must be completed. To resolve this, R1 and R2 can be combined in to one requirement for the scope of the study.	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Zenon O'young-Chu - Seattle City Light - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Shultz - Seattle City Light - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jang - Seattle City Light - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1,3,5	
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 NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

James Baldwin - James Baldwin On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - James Baldwin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Fon Hiew - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leshel Hutchings - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebika Yitna - Rebika Yitna On Behalf of: Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matt Carden - Southern Company - Southern Company Services, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. Do you agree with the modifications made in CIP-014-4 with new Requirement R2 to address the issues identified in the SAR?

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
Need further clarification on responsibilities related to separately owned but physically adjacent facilities.	
Likes 0	
Dislikes 0	
Response	

James Keele - Entergy - 3	
Answer	No
Document Name	
Comment	
R2.1. terms “line-of-site,” “proximity,” and “ease of access” are interpretive and could result in inconsistent implementation of the standard.R2 should reference Attachment 1 and not R1. “In proximity to those identified in R1” implies you have evaluated Attachment 1 and have the full R1 list and then you have to reapply the proximity criteria to the full list. Consider revising language to state the intent more clearly. For example: {C}· *R2. Each Transmission Owner shall establish a documented criteria for identifying Transmission station(s) and Transmission substation(s) in proximity. The criteria shall be used during the evaluation of Attachment 1 2.1 to identify Transmission station(s) and Transmission substation(s), irrespective of ownership, to be included in the risk assessment.*	
Likes 0	
Dislikes 0	
Response	

Matt Carden - Southern Company - Southern Company Services, Inc. - 1	
Answer	No
Document Name	
Comment	
Southern Company seeks further clarification on the proposed requirement focused on physical proximity as outlined in the criteria 2.1.1, 2.1.2, and 2.1.3. While we understand the intent behind these criteria is to enhance the resilience of the bulk power system against physical threats, we believe	

that the current language presents ambiguities that could lead to varied interpretations and implementation challenges across the industry. We respectfully request additional guidance on the following aspects:

Criteria Inclusions (2.1): The requirement should clarify whether the inclusion of all criteria in 2.1.1, 2.1.2, and 2.1.3 must be considered or does it imply that at least one of the criteria in 2.1.1, 2.1.2, and 2.1.3 must be considered.

Definition of Line-of-Sight (2.1.1): The requirement for "line-of-sight between multiple Transmission station or Transmission substation yards from a single site" raises questions about the specific conditions that constitute line-of-sight. For instance, does this criterion consider natural topography, existing infrastructure, or potential future developments that might obstruct the line-of-sight? Clarification on what constitutes an acceptable line-of-sight and any allowable exceptions would be beneficial for compliance planning.

Ease of Access from a Common Public Roadway (2.1.2): This criterion appears to prioritize ease of access from common public roadways but does not specify the degree of access required or how "ease of access" is measured. Different terrains and urban planning constraints could significantly impact the feasibility of this requirement. We suggest defining what constitutes "ease of access" and whether there are acceptable variances depending on geographic or jurisdictional factors.

Proximity and Impact of a Single Event (2.1.3): The requirement that "Transmission station or Transmission substation yards are in close enough proximity that a single event can impact multiple Transmission stations or substations" is particularly concerning due to its broad implications. We request clarification on the types of events considered under this criterion and guidance on how to assess the potential impact radius.

Since the above criteria, even with added specification, presents ambiguities that could lead to varied interpretations and implementations, Southern Company recommends a clear criterion that would include a defined physical radius, such as 100 yards, based on a technically justified single event. This would provide clear guidance that could be consistently adhered to.

Likes 0	
Dislikes 0	

Response

Kevin Conway - Western Power Pool - 4

Answer	No
Document Name	

Comment

: The Drafting Team identified a list of items to be included in the documented criteria, however, the approach is vague and requires TOs to evaluate substations “…in proximity to…[and] irrespective of ownership…” to the identified substations from R1. In practice, how would a TO of one company, especially a smaller company, be able to determine the criteria of another, independent company? “In proximity” is vague at best, overly broad at worst. How would an entity determine what is ‘in proximity”?

In R 2.1.1 the Drafting team uses the term “line-of-site” which is also vague. Line of site from where? The ground? A local elevation? A mountain? Especially in the western half of the United States, where there is a large hill overseeing a broad plain, line of site could extend for over 20 miles, and the complete service territory of a TO.

R 2.1.2 uses “common public roadway” which seems intuitive, but is actually vague. Public roadways consist of many types of construction and can be many miles from a paved surface. They may be the only way to access certain areas, especially through forested or mountainous areas.

Both R2.1.1 and R 2.1.2 are good examples of the problems with the concept the Drafting Team is trying to address, and the difficulty with being audited against language that is overly broad and flexible. Standards language should limit the auditor's ability to use subjective judgement, and provide objective and measurable performance.

Likes 0	
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Tacoma Power supports the MRO NSRF comments, as follows.

The MRO NSRF recommends including the entity's consideration of physical proximity criteria within R3, as it is part of the risk assessment methodology, rather than a standalone Requirement.

In addition, the criterion in the sub Parts of R2 are insufficiently bounded. For example:

- 2.1.1: On the flat stretches of land which make up much of the middle U.S. and Canada, line of sight can be very long distances, 10 miles or more.

-2.1.2: A common public roadway can stretch thousands of miles [U.S. Route 20 is 3,365 miles long].

-2.1.3: Mentions a single event, without bounding it as a physical attack event

This vagueness will result in too much subjectiveness during audits, and will likely be viewed differently between an entity and auditor, and even between REs. This is already occurring as illustrated in recent presentations from MRO and WECC which offer differing guidance on threat approaches. In the July 26, 2023 MRO CMEP conference, MRO was focused on the "smoking crater" scenario as a Must Have. However, at the recent March 26-27, 2024, WECC Reliability & Security Conference, WECC provided Real-World findings and Lessons Learned that vehicle borne improvised explosive devices are not a likely attack vector and may lead to misallocation of resources on unlikely threats. The threats most entities see are gunfire and copper theft. (These presentations are available on the REs' websites).

An additional challenge with the expansion of R2 to include physically adjacent stations "irrespective of ownership" is which entity is responsible under CIP-014 for protection of stations that are deemed critical and those nearby. Are both entities responsible for implementing physical protections? In the event both substations are determined applicable and a risk assessment performed, what if the separate entities' risk assessments have different conclusions or recommendations?

This also introduces additional complexities in communications between the entities, including the third party risk assessment. The MRO NSRF recommends establishing a timeline by which entities with proximate substations be required to respond to communications from Transmission Owners and the third parties performing risk assessments so there is a level of assurance that the initiating entity can meet all their required timelines.

The MRO NSRF offers additional options to adjust the criteria around physical proximity:

1. Eliminate the currently drafted sub-parts 2.1.1 – 2.1.3, and instead require that each entity establish physical proximity criteria, based on probabilistic threats for likely and realistic scenarios. This could include the requirement to consider attack history on similar facilities by frequency,

proximity, and severity when developing the criteria. This would allow each entity to determine their best definition of physical proximity based on their unique geographic areas and threats.

2. Replace criteria 2.1.1-2.1.3 with a single criterion for physical distance, “Multiple Transmission station or Transmission substation yards located within a distance of no more than 600 feet between station or substation fences.”

3. Develop criteria (e.g. weighting) for small proximate entities so that a threshold must be met to qualify. This would serve to minimize the effort in addressing small (low reliability risk to the BES) facilities.

4. Eliminate the possibility for multiple owners by revising CIP-014 to focus on single entity scenarios.

Likes 0	
Dislikes 0	

Response

Rebika Yitna - Rebika Yitna On Behalf of: Roger Brand, MEAG Power, 3, 1; - Rebika Yitna

Answer	No
Document Name	

Comment

The criteria for ‘proximity’ is subjective and could lead to different conclusions/viewpoints between the Responsible Entity and an auditor. Additional consideration is needed for Transmission station(s) or Transmission substation(s) in proximity to those identified in R1, particularly if those station(s)/substation(s) in proximity are found to be applicable and of differing ownership. This could affect an entity’s ability to properly protect (harden) the station(s)/substation(s) as well as the ability to develop a Physical Security Plan that sufficiently addresses the vulnerabilities and threats.

It is requested that the SDT consider the following:

- How does one entity coordinate with another entity from adjacent station(s)/substation(s) to gather the necessary data of the identified applicable station(s)/substation(s) to properly develop a Physical Security Plan?
- How are different conclusions/recommendations addressed between two entities’ risk based assessment documentation in designating whether an adjacent station(s) or substation(s) is applicable where each entity may have different ‘proximity’ criteria?

Likes 0	
Dislikes 0	

Response

Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova

Answer	No
Document Name	

Comment

The new R2 as it relates to proximity is vague and does not provide adequate direction to TOs on methodology or how best to evaluate proximity. We understand that all regions have unique challenges and must evaluate on a case by case basis but this is a prime candidate for a revision of the standard to ensure entities are following a prescribed methodology.

{C}1. Is it the expectation that upon an audit the TO will have to show some documentation understanding that all entities will have different forms/levels of evaluating proximity?

{C}2. Should the proximity criteria be applied after the initial run of applicable stations OR this should be done on all transmission stations whereby a completely a new set of stations that can arise.

Example 1 – Risk Assessment (as per normal practice) à use this list to then apply proximity rules to identify

additional stations as a subset

Example 2 – Risk Assessment (as per normal practice), + Proximity Rules applied to ALL stations. (this

would be used to identify two NON applicable stations that when combined meet criteria…)

Likes 0	
Dislikes 0	
Response	
Kelley Sargent - Puget Sound Energy, Inc. - 3	
Answer	No
Document Name	
Comment	

Our understanding is that R2 proximity criteria is seeking station groups with stations that are individually non-applicable under Attachment 1 Table 1, but when combined with other non-applicable stations based on proximity, may meet Attachment 1 applicability criteria. This is based on Attachment 1 Section 2.1, which seeks to combine stations – “that individually are not applicable”. If so, the current language of R2 does not agree with Attachment 1 Section 2.1.
The current requirement does not define clearly of when proximity criteria is applicable.

It will be helpful if the technical rationale document can show diagrams for possible scenarios for combining stations – NA (Non-applicable) & A (Applicable), A & A and NA & NA. R2 proximity criteria applies to the NA & NA set. A non-applicable station in proximity to an applicable station should be exempt from R2.

Likes 0	
Dislikes 0	
Response	

Lucinda Bradshaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	

Oncor does not agree that the modifications made in CIP-014-4 Requirement R2 to address the issues identified in the SAR because its proposed sub-requirements are ambiguous and fail to create the consistent approach in the identification of infrastructure critical to the operation of the BPS as sought with the SAR. Due to varying geographical locations of facilities and the overall flexibility to document the criteria used to determine proximity, inconsistencies in approaches to perform risk assessments will remain. We recommend that the R2.1 sub requirements be replaced with specific and measurable criteria. For example, the Director of National Intelligence Joint Counterterrorism Assessment Team (JCAT) has published bomb threat standoff distances in which the mandatory evacuation distances for an SUV/VAN explosive threat is 400 feet. Guidelines such as these are used by Physical Security Professionals when performing the evaluation required by CIP-014-3 R6. For consistency, we recommend that a distance between 400 feet to 1000 feet be specified in CIP-014-4 R2.

Additionally, we request clarification of the proposed R2 language concerning voltage classes applicable to stations in proximity. While the proposed R2 language points to R1 stations concerning proximity, and R1 points to Attachment 1, in which lines less than 200 kV are not applicable, it is unclear that the same “less than 200 kV” exclusion applies to those facilities that are in physical proximity to facilities to which R1 is applicable. We request that R2 be clarified to state that only facilities above 200 kV and in proximity to applicable facilities under R1 are to be considered.

Likes 0	
Dislikes 0	
Response	

Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1 - RF	
Answer	No
Document Name	
Comment	

. ”Line of sight" is not defined clearly. Clarification is needed to determine if it refers to the highest point (i.e., the pole/microwave tower) in the substation yard or does "line of sight" refer to ground level in the substation yard? Additionally, “event” is not clearly scoped.

"Irrespective of ownership" language entangles Responsible Entities. Transmission substations seem to be moving away from the 100kV bright-line NERC criteria in the latest CIP-002-Y draft. Therefore, transmission substations owned by other Transmission Owners will require Registered Entities to evaluate substations that they do not own. This will require entities to dedicate unknown resources to be engaged with the other Responsible Entity(ies) in the 36 month timeframe to conduct the assessments.

Likes 0	
Dislikes 0	
Response	

Michele Tondalo - United Illuminating Co. - 1

Answer	No
Document Name	
Comment	

Comment 5: In CIP-014-4 R2 and Attachment 1 the terms “Transmission station”, “Transmission substation”, “Transmission facilities”, and “substation yards” are used in similar context. Suggest that the terms used in the standard be reviewed to ensure that any changes in terminology are intentional.

Comment 6: In the context of CIP-014-4 R2 line-of-sight can have significantly different impacts when considering other factors such as time of year (leaves on trees vs. not on trees), urban vs. rural, etc. In an urban setting a station could be a block or two away and not be considered line-of-sight but still be extremely close. Suggest that R2.1 wording be changed to the following: “The criteria shall at a minimum consider the following…” Using the term “consider” would allow for Transmission Owners to document in their rationale how the considerations like line of sight is, or is not used.

Comment 7: In multiple places in the standard the term “…or…” is used, e.g., R2.1.1 “…Transmission station or Transmission substation yards…” Suggest that these instances be reviewed and reworded to include “…and/or…” as appropriate.

Comment 8: Attachment 1 Item 2.1 references the ability to combine stations that are “..individually not applicable…” so that they are included in the CIP-014 assessment with a combined Average Weighted value. However, R2 is identified as for defining how to determine proximity considerations for stations “…in proximity to those identified in Requirement R1…”

Suggest that R2 be reworded as follows:

“…in proximity to those identified in Requirement R1, or through Attachment 1 Criterion 2.1, irrespective of ownership, that shall be included in the risk assessment.”

Likes 0	
Dislikes 0	
Response	

Michele Shafer - New York State Electric & Gas (NYSEG) - 6

Answer	No
Document Name	
Comment	

- In CIP-014-4 R2 and Attachment 1 the terms “Transmission station”, “Transmission substation”, “Transmission facilities”, and “substation yards” are used in similar context. Suggest that the terms used in the standard be reviewed to ensure that any changes in terminology are intentional.
- In the context of CIP-014-4 R2 line-of-sight can have significantly different impacts when considering other factors such as time of year (leaves on trees vs. not on trees), urban vs. rural, etc. In an urban setting a station could be a block or two away and not be considered line-of-sight but still be extremely close. Suggest that R2.1 wording be changed to the following: “The criteria shall at a minimum **consider** the following…” Using the term “consider” would allow for Transmission Owners to document in their rationale how the considerations like line of sight is, or is not used.
- In multiple places in the standard the term “…or…” is used, e.g., R2.1.1 “…Transmission station or Transmission substation yards…” Suggest that these instances be reviewed and reworded to include “…**and/or**…” as appropriate.
- Attachment 1 Item 2.1 references the ability to combine stations that are “..individually not applicable…” so that they are included in the CIP-014 assessment with a combined Average Weighted value. However, R2 is identified as for defining how to determine proximity considerations for stations “…in proximity to those identified in Requirement R1…”
  Suggest that R2 be reworded as follows:

"…in proximity to those identified in Requirement R1**, or through Attachment 1 Criterion 2.1**, irrespective of ownership, that shall be included in the risk assessment."

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	

Comment

The MRO NSRF recommends including the entity's consideration of physical proximity criteria within R3, as it is part of the risk assessment methodology, rather than a standalone Requirement.

In addition, the criterion in the sub Parts of R2 are insufficiently bounded. For example:

- 2.1.1: On the flat stretches of land which make up much of the middle U.S. and Canada, line of sight can be very long distances, 10 miles or more.

- 2.1.2: A common public roadway can stretch thousands of miles [U.S. Route 20 is 3,365 miles long].

- 2.1.3: Mentions a single event, without bounding it as a physical attack event

This vagueness will result in too much subjectiveness during audits, and will likely be viewed differently between an entity and auditor, and even between REs. This is already occurring as illustrated in recent presentations from MRO and WECC which offer differing guidance on threat approaches. In the July 26, 2023 MRO CMEP conference, MRO was focused on the "smoking crater" scenario as a Must Have. However, at the recent March 26-27, 2024, WECC Reliability & Security Conference, WECC provided Real-World findings and Lessons Learned that vehicle borne improvised explosive devices are not a likely attack vector and may lead to misallocation of resources on unlikely threats. The threats most entities see are gunfire and copper theft. (These presentations are available on the REs' websites).

An additional challenge with the expansion of R2 to include physically adjacent stations "irrespective of ownership" is which entity is responsible under CIP-014 for protection of stations that are deemed critical and those nearby. Are both entities responsible for implementing physical protections? In the event both substations are determined applicable and a risk assessment performed, what if the separate entities' risk assessments have different conclusions or recommendations?

This also introduces additional complexities in communications between the entities, including the third party risk assessment. The MRO NSRF recommends establishing a timeline by which entities with proximate substations be required to respond to communications from Transmission Owners and the third parties performing risk assessments so there is a level of assurance that the initiating entity can meet all their required timelines.

The MRO NSRF offers additional options to adjust the criteria around physical proximity:

1. Eliminate the currently drafted sub-parts 2.1.1 – 2.1.3, and instead require that each entity establish physical proximity criteria, based on probabilistic threats for likely and realistic scenarios. This could include the requirement to consider attack history on similar facilities by frequency, proximity, and

severity when developing the criteria. This would allow each entity to determine their best definition of physical proximity based on their unique geographic areas and threats.

2. Replace criteria 2.1.1-2.1.3 with a single criterion for physical distance, “Multiple Transmission station or Transmission substation yards located within a distance of no more than 600 feet between station or substation fences.”

3. Develop criteria (e.g. weighting) for small proximate entities so that a threshold must be met to qualify. This would serve to minimize the effort in addressing small (low reliability risk to the BES) facilities.

4. Eliminate the possibility for multiple owners by revising CIP-014 to focus on single entity scenarios.

Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	

Response

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB

Answer	No
Document Name	

Comment

TVA disagrees with the changes to R2 given the requirement’s lack of focus on plausible and likely physical attacks, as well as the general lack of flexibility for a Functional Entity to define events based on evidence which may trigger the evaluation of separate facilities in aggregate. Additionally, R2 should require that stations evaluated for proximity be Applicable stations per Attachment 1 and the applicability criteria.

TVA proposes two (2) alternative phrasings of R2, requirement R2.1:

2.1. The criteria shall, at a minimum, include whether the Transmission station or Transmission substation yards are in close enough proximity that a single event can impact multiple Transmission stations or Transmission substations. Determining the proximity of Transmission station or Transmission substation yards that may be impacted by a single event may include:

2.1.1. Line-of-sight between multiple Transmission station or Transmission substation yards from a single site.

2.1.2. Ease of access from a common public roadway that exists between multiple Transmission station or Transmission substation yards.

2.1.3. Historical event analysis or threat assessment.

----- OR -----

2.1. The criteria shall at a minimum include the following:

2.1.1. Line-of-sight between multiple Transmission station or Transmission substation yards from a single site **and**,

2.1.2. Ease of access from a common public roadway that exists between multiple Transmission station or Transmission substation yard **and**, 2.1.3. The Transmission station or Transmission substation yards are in close enough proximity that a single event can impact multiple Transmission stations or Transmission substations **based on analysis of previous events or threat assessment**.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Insitute (EEI) and MRO NSRF for question #3.	
Likes 0	
Dislikes 0	
Response	
Leshel Hutchings - AEP - 3	
Answer	No
Document Name	
Comment	
Remove 2.1 and all sub-bullets. Line-of-sight, ease of access, and close physical proximity are vague language open for interpretation – makes this difficult to audit and determine compliance. Can the SDT replace 2.1.1-2.1.3 with a distance radius without specifying the type of attack (i.e. 1000 ft of separation between station perimeters?). We are concerned that a TO may have a methodology and technical rationale based on historical or active threats to their system but that an auditor may have a completely different threat vector in their mind to protect against. The standard language should be such that it is decisively and objectively clear that an entity is in compliance. Additionally, the intent is to identify close physical proximity such that a singular event could impact both stations; other ranges are irrelevant. **Emphasize explicitly in the standard language or Guidelines and Technical Basis that this considers only a single, simultaneous attack**. Considering non-simultaneous attacks makes the number of scenarios infinite and is not feasible to analyze or protect against. Bringing in proximity factors like "a common public roadway" alludes to non-simultaneous attack and should be removed. SDT may want to consider a closed conversation	

with the E-ISAC for an industry-wide perspective from security professionals on the calculated risk of simultaneous BES substation attacks and the most significant threat vectors seen by North American utilities.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes interpretation of the proximity text is highly subjective, and is confusing because it is not tied to a threat vector. In crossing ownership lines, in failing to explicitly limit ownership to other Registered Entities subject to NERC regulations, and in implying some level of coordination will result, the language seems more suited to one of the transmission planning functions rather than the Transmission Owner function. There is also insufficient detail about which entities will be expected to take actions, and what actions, once one entity deems another entity's site "critical" due to proximity. Are the added sites required to be protected, or can they be studied and ruled out for added security protections? One interpretation suggests that a requirement to circle back and perform multiple studies is being created. The original intent of CIP-014 was to identify a very small number of the absolutely most critical substations. Requiring Registered Entities to expand their lists using proximity as a criterion in R2 is contrary to the original intent of the standard.	
Likes 0	
Dislikes 0	
Response	
Karen Demos - NextEra Energy - Florida Power and Light Co. - 3	
Answer	No
Document Name	
Comment	
NextEra/FPL supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	

Answer	No
Document Name	
Comment	

WAPA recommends including the entity’s consideration of physical proximity criteria within R3, as it is part of the risk assessment methodology, rather than a standalone Requirement.

In addition, WAPA concurs with the comments provided by the MRO NSRF. WAPA has significant concerns around the ambiguity and the potential that the number of “groups” of substations now bounded by physical security criteria would lead to a double or triple of sites requiring assessment.

WAPA concurs with additional options provided by the MRO NSRF to adjust the criteria around physical proximity.

Likes 0	
Dislikes 0	
Response	

Michael Dillard - Austin Energy - 5, Group Name Austin Energy

Answer	No
Document Name	
Comment	

Austin Energy supports MRO's comments. Attached in Question 1.

Likes 0	
Dislikes 0	
Response	

Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group

Answer	No
Document Name	
Comment	

Requirement R2.1.1 may cause a significant increase in the number of applicable facilities to include in the risk assessment that may not effectively achieve the intent of the changes as explained in the NERC report entitled, *Evaluation of the Physical Security Reliability Standard and Physical Security Attacks to the Bulk-Power System*. The report focused on the intent of modifying existing Reliability Standards for sake of improving BPS resiliency to physical attacks events such as those that occurred in Moore County, NC in 2022 and identified a lack of consistency. In these events, as well as others referenced in the report, transformers have more frequently been damaged by means of ballistic attack. Use of the term “line-of-sight” will likely require clarification in each TOP’s documented criteria and possibly introduce more inconsistency amongst TOP risk assessments. Instead, changing the minimum requirement listed by R2.1.1 to require entities to study the loss of power transformers in applicable stations accomplishes the goal of assessing the impacts caused by ballistic attacks to the equipment most likely to be victim of these events, while also improving assessment consistency amongst TOPs. *See further comments from the previous item as well.*

Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	

NEE support's EEI comments: "EEI proposes the following modification:

R2. Each Transmission Owner shall establish and implement**apply** documented criteria for identifying Transmission station(s) and Transmission substation(s) in proximity to those identified in Requirement R1, irrespective of ownership, that shall be included in the risk assessment. "

Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	

Tri-State agrees with the MRO NSRF Submitted Comments

Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No

Document Name	
Comment	

SMUD agrees that proximity criteria are needed in CIP-014-4, however, “proximity” needs to be bound. The proximity criteria should be defined so that all entities can easily determine if the proximity criteria makes a Transmission station or Transmission substation applicable or not. The terms “line of sight”, “ease of access”, and “single event” in sub-requirements R2.1.1, R2.1.2, and R2.1.3, respectively, are all subjective terms and will have different meanings among Transmission Operators. As currently written, CIP-014-4 is not auditable.

The Standard Drafting Team should simplify the proximity criteria by creating a fixed, physical distance that can be measured and easily applied by all Transmission Owners. SMUD suggests a fixed distance of 600 feet, regardless of line of sight, or some other fixed distance that makes sense with physical security experts. A fixed physical distance would also eliminate proximity differences between Transmission Owners.

Likes 0	
Dislikes 0	
Response	

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	No
Document Name	
Comment	

Black Hills Corporation disagrees with the proposed new Requirement R2. Black Hills Corporation recommends that the SAR drafting team clearly define criteria to be used in the CIP-014 studies similar to what was done within Table 1 (footnote 11) of TPL-001-5 for defining the criteria of “common structure” circuits. Black Hills Corporation has concerns about leaving vague language that leaves the requirement open to auditor interpretation.

Likes 0	
Dislikes 0	
Response	

Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF

Answer	No
Document Name	
Comment	

Duke Energy would like to see clarity that the criteria in R2 are tied to likely threat vectors and the protections that can be reasonably implemented. The ambiguity in threat vector makes how to perform the evaluation of the criteria in R2.1 unclear. Duke Energy supports the inclusion of criterion 2.1.1 but proposes that any additional criteria be determined by the entity based by likely threats identified by the entity. As written today, the criteria in R2 and the R3 risk assessment methodology do not clearly align.

Likes 0	

Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	

Comment

While Dominion Energy supports EEI comments in general, Dominion Energy does not agree with the modifiactions as Entities are not capable of assessing risk and obtaining the required information to assess any risks for facilities that are not owned by the Entity. For R2.1 this requirement is not feasible, and it incurs unreasonable expenses for a limited reliability benefit. The impact of a facility in line of sight is an extreme contingency and does not add a reliability value based on the cost to study and potentially upgrade a station merely because of proximity.

Dominion Energy agrees that R2.1.2 is appropriate to be considered for an identified facility but not in the evaluation of a facility that is high risk to grid reliability.

R2.1.3 is an extreme contingency that is unlikely to occur and there is no value in adding this to the identification or study process.

Likes 0	
Dislikes 0	

Response

John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	

Comment

Regarding *3.2. "Analysis at System peak, Off-Peak Load, and other System conditions susceptible to instability, uncontrolled separation, or Cascading within an Interconnection shall be conducted in dynamic and steady state simulations."* Please clarify what other conditions are, i.e. further describe case assumptions.

Likes 0	
Dislikes 0	

Response

Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	No
Document Name	

Comment	
Eversource believes that this section needs to be re-written such that the only criteria is the physical distance between stations/yards. The reason why this section should be changed is that "line-of-sight" is subjective, changes throughout the year (leaves on trees), and may vary based on elevation changes (using a ladder or drone). "Common public roadway" is undefined and irrelevant since a private roadway or ATV trail is just as relevant. For R1.3, represent "in close enough proximity" as a physical distance.	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez

Answer	No
Document Name	
Comment	
SRP supports the MRO NSRF with Tacoma Power's comments. In addition, when there are multiple facilities owned by different entities in close proximity to each other that individually would not be in scope, would this requirement make one or more facilities now applicable to CIP-014 if assessed together? How are entities supposed to deal with this scenario? Does an entity have to get with the other entity to make sure their security plan works with each other's plan? What is the expectation for an entity to do we do with other entity's information?	
Likes 0	
Dislikes 0	
Response	

Teresa Krabe - Lower Colorado River Authority - 5

Answer	No
Document Name	
Comment	
This could prove to be challenging and inconsistent. An Entity is required to study facilities owned by other Registered Entities but then what? What if one of the proximity stations is deemed critical from the planning process? Who would be responsible for ensuring that these facilities are adequately protected. What if a facility is low voltage (69kV) and the owner is not registered with NERC; how will this be handled? R2 creates a requirement but does not give any guidance on how to implement.	
Likes 0	
Dislikes 0	

Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	

Thank you for the chance to comment, SERC appreciates the complexity of the SDT's task of modifying multiple parts of such a high-profile and high-priority standard.

· Item #2.A R2.1.1 includes the term "line-of-sight" as a criteria, which is nebulous and difficult to demonstrate in compliance evidence; providing clear expectations on inclusion is part of the SAR, both in Project Scope #4: "*Clarify what study scenario(s) and other study assumptions are appropriate and reasonable considering the intent of CIP-014-3 and the potential range of issues during a physical attack…"* and SAR Detailed Description #5. One key issue with using line of sight (especially away from a transmission right-of-way is that it changes over time). For example, today a forest of trees obscures a common viewpoint from seeing two substations – but after logging activity or when leaves fall off trees in autumn, now a clear line of sight exists. Another field observed example is where two substations exist near a flat suburban area with dense tree and vegetation cover, but in a few months a low-rise office building offers a new vantage point. Line-of-sight locations usable by an attacker may also not be able to be accurately assessed if the utility does not have legal permission to access privately owned land or structures adjacent to their substation. We would note that the similar term "Clear line of sight" is footnoted in FAC-003-4, however this is not in a security context and applies to Right of Way areas that are generally free of vegetation, as well as disallowing the use of magnified optics. The SDT should consider instead using a specific distance metric that can be readily calculated in a GIS or similar system, is preserved and demonstrable/conclusively measurable as evidence during compliance monitoring, consistent when two or more Responsible Entities own substation Elements in proximity and would allow for reassessment if planned new construction or substation expansion will occur in the 36-month R1 study window. We might suggest the proximity discussion instead look at a 1-kilometer radius from any point, where if any Transmission Element from one substation is within 2 kilometers of another Transmission Element, those would be considered as a proximity group or locus to be studied together. This (or a substitute distance of the SDT's choosing) would represent the maximum probable effective engagement distance of a BES Element-sized target by an attacker.

· Item #2.B R2.1.1 includes the term "line-of-sight" as a criteria. While this phrase did come from NERC's CIP-014-3 R1 Practice Guide as items to question/consider, in a compliance requirement this is likely inadequate to describe the susceptibility of a group of Transmission Elements to a common attack. This may inappropriately simplify attack methods, contrary to what the SAR outlines in Project Scope #4: "*Clarify what study scenario(s) and other study assumptions are appropriate and reasonable considering the intent of CIP-014-3 and the potential range of issues during a physical attack…"* Line-of-sight is largely an issue for direct fire type attacks, but is not a sufficient enough discriminator to cover for other ranges of attack types (such as surreptitious entry or insider threat), or for groups of attackers who are coordinated/mobile during an attack event – as seen in the attacks in Moore County NC in 2022, the Pacific Northwest in 2022, and Idaho in 2023. The use of a proximity based metric (mentioned in Item 2.A above) could alleviate some of these concerns.

· Item #2.C R2.1.3 mentions proximity for a "single event". While the context of a "single event" (happening in a very precise, sub-second timeframe) does make some sense for dynamic studies, a history of physical attacks in Metcalf in 2013, Arkansas in 2013, Moore County NC in 2022, the Pacific Northwest in 2022, and Idaho in 2023 (among others) has shown that actual attacks can consist of multiple attackers/sequential attack actions (see comment Item #2.B above for examples) which may effect the steady state of the BES over a slightly longer timeframe (minutes) vs the dynamic (seconds/cycles). Suggest that the "single event" language be limited to dynamic studies, or eliminated.

· Item #2.D R2.1.3 mentions proximity for a "single event". Is it correct to read that this 'single event' would involve both the loss of communication and system protection in R3.6 as well followed by the introduction of the fault characteristics of R3.3? Or would that be considered multiple "events"?

· Item #2.E R2 states, "irrespective of ownership", so would transmission planners be reliant on access to information (in R1, R2, and R3.6, especially if it involves details of installations in the future as far as 36 months) that may be difficult to get from neighboring entities for purposes of setting up and accurately performing their analysis? If so, the SDT may want to consider adding a requirement that neighboring entities receiving requests for information related to CIP-014 must comply with providing the necessary information for study purposes, or some remedy for communication requests that are not responded to.

Likes 0	
Dislikes 0	

Response

Jeffrey Streifling - NB Power Corporation - 1

Answer	No
Document Name	

Comment

We are unsure what the Drafting team meant by “proximity to” in R2 and part 2.1.3.

We are unsure what a “common public roadway” is. How is common public roadway different from a public roadway. Additionally, what does “Ease of access” mean for a Common Public roadway?

Likes 0	
Dislikes 0	

Response

Mark Flanary - Midwest Reliability Organization - 10

Answer	No
Document Name	

Comment

As the Requirement is currently written there is no obligation to review the stations or substations identified for risk assessment due to proximity after the initial creation. Consider adding a timing component in R2 such as "at least every 36 months."

The phrase “in proximity to those identified in Requirement R1” is not appropriate as the purpose is to find even substations that are “individually are not applicable, but are applicable when combined based on physical adjacency”. Consider removing from the Requirement "in proximity to those identified in Requirement R1".

While the Requirement takes a step towards addressing proximity by providing Entities flexibility in their criteria it also provides a lot of room for interpretation by Entities, unaffilicated third party verifiers, and oversight. Consider adding to the Technical Rationale guidance or examples regarding what "line-of-sight" and "close enough proximity" mean.

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	No
Document Name	
Comment	
We are unsure what the Drafting team meant by "proximity to" in R2 and part 2.1.3. We are unsure what a "common public roadway" is. How is common public roadway different from a public roadway. Additionally, what does "Ease of access" mean for a Common Public roadway?	
Likes 0	
Dislikes 0	
Response	

Fon Hiew - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	No
Document Name	
Comment	
We are unsure what the Drafting team meant by "proximity to" in R2 and part 2.1.3. We are unsure what a "common public roadway" is. How is common public roadway different from a public roadway. Additionally, what does "Ease of access" mean for a Common Public roadway?	
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	

MPC concurs with the MRO NSRF’s comments.

Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO-NSRF and EEI's comments.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren supports EEI's comments on this project.	
Likes 0	
Dislikes 0	
Response	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI proposes the following modification:	

R2. Each Transmission Owner shall establish and **apply** documented criteria for identifying Transmission station(s) and Transmission substation(s) in proximity to those identified in Requirement R1, irrespective of ownership, that shall be included in the risk assessment.	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	
The concept of the risk assessment in the currently approved standard and this draft is ambiguous and is interpreted differently across the industry. The standard requirements need additional clarification as to what type of risk (explosive, gunshot, etc) the TO should be protecting against. It is important to keep in mind that the clarification on the risk should take into account the premise that physical security measures may be installed pursuant to the assessment of this risk.	
Likes 0	
Dislikes 0	
Response	
James Baldwin - James Baldwin On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - James Baldwin	
Answer	No
Document Name	
Comment	
This could prove to be challenging and inconsistent. An Entity is required to study facilities owned by other Registered Entities but then what? What if one of the proximity stations is deemed critical from the planning process? Who would be responsible for ensuring that these facilities are adequately protected. What if a facility is low voltage (69kV) and the owner is not registered with NERC; how will this be handled? R2 creates a requirement but does not give any guidance on how to implement.	
Likes 0	
Dislikes 0	
Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	

Answer	No
Document Name	
Comment	

The R2 criteria, as currently written, are open-ended, making consistent evaluation between entities and auditors impossible. Adding an explicit upper bound to limit the scope would enhance clarity and consistency.

IID proposes consolidating criteria 2.1.1 through 2.1.3 into a single criterion based on physical distance, as follows: “Multiple Transmission station or Transmission substation yards located within 600 feet between station or substation fences.”

Expanding the scope to include physically adjacent facilities regardless of ownership is both costly and redundant. It raises the question of whether both entities will share responsibility for physical security protections.

Likes 0	
Dislikes 0	
Response	

Jesus Sammy Alcaraz - Imperial Irrigation District - 1

Answer	No
Document Name	
Comment	

The R2 criteria, as currently written, are open-ended, making consistent evaluation between entities and auditors impossible. Adding an explicit upper bound to limit the scope would enhance clarity and consistency.

IID proposes consolidating criteria 2.1.1 through 2.1.3 into a single criterion based on physical distance, as follows: “Multiple Transmission station or Transmission substation yards located within 600 feet between station or substation fences.”

Likes 0	
Dislikes 0	
Response	

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	No
Document Name	
Comment	

See comments submitted by the Edison Eclectic Institute

Likes 0	

Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	
We are unsure what the Drafting team meant by "proximity to" in R2 and part 2.1.3. We are unsure what a "common public roadway" is. How is common public roadway different from a public roadway. Additionally, what does "Ease of access" mean for a Common Public roadway?	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy supports the EEI response to this question.	
Likes 0	
Dislikes 0	
Response	
Michael Jang - Seattle City Light - 1	
Answer	No
Document Name	
Comment	
Providing support based on SCL SME's opinion: There are no "clear expectations regarding the inclusion of physically adjacent elements," as the SAR requests. The adjacency criteria leave a lot of room for interpretation and potential conflicts between adjacent owners. The requirements for determining adjacency should be more explicit and,	

ideally, moved to Attachment 1, since it impacts applicability. The circular references from R2 to R1, R1 to Attachment 1, and Attachment 1 to R2 create room for confusion.

We disagree with the inclusion of “ease of access from a common public roadway that exists between multiple Transmission stations” as a reasonable thing to consider. Driving between stations (that don’t already meet line-of-sight or proximity criteria) would take on the order of minutes, whereas protection systems (even with delayed clearing) and transient stability analyses cover things on the order of seconds or less.

It is also unclear how shared responsibility will work for adjacent stations with different ownership, especially in the case where one substation is significantly smaller than the other.

Likes 0	
Dislikes 0	

Response

Chris Shultz - Seattle City Light - 5

Answer	No
Document Name	

Comment

There are no “clear expectations regarding the inclusion of physically adjacent elements,” as the SAR requests. The adjacency criteria leave a lot of room for interpretation and potential conflicts between adjacent owners. The requirements for determining adjacency should be more explicit and, ideally, moved to Attachment 1, since it impacts applicability. The circular references from R2 to R1, R1 to Attachment 1, and Attachment 1 to R2 create room for confusion.

We disagree with the inclusion of “ease of access from a common public roadway that exists between multiple Transmission stations” as a reasonable thing to consider. Driving between stations (that don’t already meet line-of-sight or proximity criteria) would take on the order of minutes, whereas protection systems (even with delayed clearing) and transient stability analyses cover things on the order of seconds or less.

It is also unclear how shared responsibility will work for adjacent stations with different ownership, especially in the case where one substation is significantly smaller than the other.

Likes 0	
Dislikes 0	

Response

Carver Powers - Utility Services, Inc. - 4

Answer	No
Document Name	

Comment

For requirement 2.1.3, request clarification on what would be considered as a “single event.” Do natural disasters count as a single event (i.e., Hurricane, flood)? The SAR provided an example of what a “single event” could be (e.g., debris field from incendiary device.) Request that this example in the SAR or something similar be included in the modifications.

For section 2.1.2, request clarification on “ease of access”, Does a fence, gate, or a speedbump limit the ease of access concern? Recommend providing guidance in either the standard or technical rationale.

Likes 0	
Dislikes 0	

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

See EEI comments

Likes 0	
Dislikes 0	

Response

Robert Jones - Seattle City Light - 4

Answer	No
Document Name	

Comment

There are no “clear expectations regarding the inclusion of physically adjacent elements,” as the SAR requests. The adjacency criteria leave a lot of room for interpretation and potential conflicts between adjacent owners. The requirements for determining adjacency should be more explicit and, ideally, moved to Attachment 1, since it impacts applicability. The circular references from R2 to R1, R1 to Attachment 1, and Attachment 1 to R2 create room for confusion.

We disagree with the inclusion of “ease of access from a common public roadway that exists between multiple Transmission stations” as a reasonable thing to consider. Driving between stations (that don’t already meet line-of-sight or proximity criteria) would take on the order of minutes, whereas protection systems (even with delayed clearing) and transient stability analyses cover things on the order of seconds or less.

It is also unclear how shared responsibility will work for adjacent stations with different ownership, especially in the case where one substation is significantly smaller than the other.

Likes 0	

Dislikes 0	

Response

Daren Brubaker - Seattle City Light - 6

Answer	No
Document Name	

Comment

There are no “clear expectations regarding the inclusion of physically adjacent elements,” as the SAR requests. The adjacency criteria leave a lot of room for interpretation and potential conflicts between adjacent owners. The requirements for determining adjacency should be more explicit and, ideally, moved to Attachment 1, since it impacts applicability. The circular references from R2 to R1, R1 to Attachment 1, and Attachment 1 to R2 create room for confusion.

We disagree with the inclusion of “ease of access from a common public roadway that exists between multiple Transmission stations” as a reasonable thing to consider. Driving between stations (that don’t already meet line-of-sight or proximity criteria) would take on the order of minutes, whereas protection systems (even with delayed clearing) and transient stability analyses cover things on the order of seconds or less.

Likes 0	
Dislikes 0	

Response

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott

Answer	No
Document Name	

Comment

Comments: ITC proposes the following modifications:

R2. Each Transmission Owner shall establish and **apply** documented criteria for identifying Transmission station(s) and Transmission substation(s) in proximity to those identified in Requirement R1, that shall be included in the risk assessment.

2.1. The criteria shall include at a minimum one or more of the following: (Convert list to bullets)

-
    - Line-of-sight between multiple Transmission station or Transmission substation yards from a single site.
    - Ease of access from a common public roadway that exists between multiple Transmission station or Transmission substation yards.
    - The Transmission station or Transmission substation yards are in close enough proximity that a single event can impact multiple Transmission stations or Transmission substations
    - Mileage between multiple Transmission station or Transmission substation yards from a single site.

Likes 0	

Dislikes 0	
Response	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
Answer	No
Document Name	
Comment	

PNM and TNMP support EEI comments regarding R2, noted again here. Additionally, we request the SDT consider removing R2.1.1. Line-of-sight varies significant based on weather conditions, land surfaces, etc. Defining a distance between station would be a better criterion than line-of-sight.

"EEI proposes the following modification:

*R2. Each Transmission Owner shall establish and implement**apply** documented criteria for identifying Transmission station(s) and Transmission substation(s) in proximity to those identified in Requirement R1, irrespective of ownership, that shall be included in the risk assessment."*

Likes 0	
Dislikes 0	
Response	
Zenon O'young-Chu - Seattle City Light - 3	
Answer	No
Document Name	
Comment	

1. There are no "clear expectations regarding the inclusion of physically adjacent elements," as the SAR requests. The adjacency criteria leave a lot of room for interpretation and potential conflicts between adjacent owners. The requirements for determining adjacency should be more explicit and, ideally, moved to Attachment 1, since it impacts applicability. The circular references from R2 to R1, R1 to Attachment 1, and Attachment 1 to R2 create room for confusion.
2. We disagree with the inclusion of "ease of access from a common public roadway that exists between multiple Transmission stations" as a reasonable thing to consider. Driving between stations (that don't already meet line-of-sight or proximity criteria) would take on the order of minutes, whereas protection systems (even with delayed clearing) and transient stability analyses cover things on the order of seconds or less.
3. It is also unclear how shared responsibility will work for adjacent stations with different ownership, especially in the case where one substation is significantly smaller than the other.

Likes 0	
Dislikes 0	
Response	
Jason Snodgrass - Jason Snodgrass On Behalf of: Katrina Lyons, Georgia System Operations Corporation, 3, 4; - Jason Snodgrass	
Answer	No

Document Name	
Comment	
GSOC supports comments provided by Georgia Transmission	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Requirement 2 should be further clarified since it's intent and what was explained in the webinar don't align. Is the proximity requirement in addition to what was identified in Requirement 1 or is it only stations established in Requirement 1?"	
Likes 0	
Dislikes 0	
Response	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO, Group Name Manitoba Hydro Group	
Answer	Yes
Document Name	
Comment	
MH agrees with documenting proximity criteria to identify multiple transmission stations/substations. However, the line-of-sight is subjective to the location and each TO is required to develop its physical proximity criteria based on its unique geographical location and physical threats.	
Likes 0	
Dislikes 0	
Response	
Tyler Schwendiman - ReliabilityFirst - 10	
Answer	Yes
Document Name	

Comment	
For R2.2.1.2, the term “ease of access” is not a defined term and may result in difficulty to provide evidence or audit. Suggest using more definitive terms like, “shares access”	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no objection to the modifications made to R2.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Exelon supports the EEI comment to clarify the actions required in R2.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	

Requirement R2.1.1 needs to state “one or more” versus “multiple” unless the adjacency only applies to line-of-site inclusion of two or more Transmission station(s) or Transmission substation(s) from the primary applicable Transmission station/substation. Remove the term “yards” as some Transmission Owners have enclosed Transmission station(s) (e.g., rock/brick walls) where a line-of-sight determination could not be made from within the yard. How does this fit for underground Transmission station(s) or Transmission substation(s)? The term “line-of-sight” is open to a great deal of interpretation here. For “clear line of sight” (no hyphens by the way) used in FAC-003 there is a footnote stating ““Clear line of sight” means the distance that can be seen by the average person without special instrumentation (e.g., binoculars, telescope, spyglasses, etc.) on a clear day.” In the case of CIP-014, the Standard is focused on physical security and the potential adversaries identified in the Requirement R4 threat and vulnerability assessment may very well select locations using weapons/tools that have a “line of sight” from the weapon/tool’s perspective (e.g., range finders, laser targeting tools, etc.). Advanced rifle scopes with ballistic calculators enable precise targeting of critical components from distances exceeding 1 kilometer. Night vision and thermal scopes enhance the ability to engage targets in low-light or no-light conditions, facilitating nighttime operations and reducing the likelihood of immediate detection. If more than one Transmission station/substation is within line of sight of the primary applicable Transmission station/substation are all combined as a single loss to study in the risk assessment? This needs to be clear so multiple line-of-sight Transmission station/substation conditions are studied effectively.

Requirement R2.1.2 needs to state “one or more” versus “multiple”. Additionally, what is the intent with regards to distance between Transmission station(s)/substation(s) having “ease of access from a common public roadway”? Certainly, potential adversaries identified in the Requirement R4 threat and vulnerability assessment could damage one Transmission station and drive to other Transmission stations sharing the road but is that within a quarter mile or 50 miles?

Requirement 2.1.3 Remove “yards”. Using “single event” may limit the perspective of the assessment of risk in terms of multiple sites being attacked by a single adversary or group of adversaries not occurring at the same instant. An entity may not consider a series of attacks over a short timeline as a “single” event which would impact the assessment of the risk. Certainly, there is a fine line to draw but use of the term “single” will be leveraged to limit compliance risk while the operational risk is still in effect (with no mitigation efforts initiated.)

Cooperation and coordination between owners with substations in close proximity needs to be emphasized in some manner. Understanding what a neighbor has in the substation and reflecting that in the model is a step to ensure the risk assessment is effective.

Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

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

Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
LG&E and KU suggest the following with regard to what constitutes sufficient “ease of access from a common public roadway": the Drafting Team should consider the inclusion of a hard threshold for exclusion, akin to TPL-001 1-mile threshold for common structures or right-of-way. For example, “R2.2 Transmission stations or Transmission substations more than 1/2-mile from those identified in Requirement R1 may be excluded in the risk assessment.” In this way, entities may still establish criteria to determine when stations are within sufficient proximity, but they are also given a “brightline" option to use if they prefer. Two stations may be separated by 10 miles of common highway. That would seem to be easy access, but also too far apart for a single attack.	
Likes 0	
Dislikes 0	
Response	

4. Do you agree with the modifications made in CIP-014-4 with new Requirement R3 to address the issues identified in the SAR?

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
ACES feels R3.1 and it's sub requirements are too prescriptive and extend beyond what is listed in the SAR. The main goal of the SAR is to ensure the inclusion of dynamic studies in the risk assessment and increase clarity around criteria to identify instability, uncontrolled separation or Cascading. The additional requirements extend beyond the scope of the SAR.	
Likes 0	
Dislikes 0	
Response	

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	

SAR did not request a 3-phase bolted fault to be evaluated for a stability analysis. The SAR required clarifying to include transient stability analysis at a minimum, but not specifying the exact type of faults to be analyzed. A bolted 3-phase bolt is a very unlikely event that can occur at a station where every transmission line, transformer and other facilities would experience the fault simultaneously. Potential system impact with bolted 3-phase fault would require costly physical security mitigation for a highly unlikely and low probability event. The standard should leave some flexibility as to what type of fault event should be evaluated and include sufficient technical rationale to support it.

The SAR did not require all criteria listed in the R3.1 to be used in the identification of instability. Defining a fixed MW value for generation or load loss should not be required if the assessment does not conclude that it would risk instability, uncontrolled separation or Cascading.

Obtaining actual clearing times places additional burdens on our System Protection engineers and will also increase the complexity and time necessary to develop scripts for simulating these contingencies with minimal benefit. The operating times we currently employ are reasonable estimations generated after consultation with our System Protection group. They are based on our standard protection schemes and are typically more conservative than the actual operating times.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	No
Document Name	

Comment

There will not be consistency in the development of "acceptable" load/generation loss. Perhaps the RC should determine what that acceptable level is to provide consistency within an RC footprint and/or Interconnection. Appears that there should be a word in front of “post-event response” to clearly indicate the need for technical rational regarding the post-event response. It is not clear how some bulleted items are “used”. Consider consolidating some bulleted items by simply indicating System Operating Limits. The new definition from Project 2015-09 is “All Facility Ratings, System Voltage Limits, and stability limits, applicable to specified System configurations, used in Bulk Electric System operations for monitoring and assessing pre- and post-Contingency operating states.” This would remove 1,3,4,5,6, and 12 (specific examples could be covered in the Technical Rational). “Loss of IBR Generation” needs some context in terms of amount. Unclear what “Cascading line tripping” is in this context of evaluating whether Cascading would occur. Is the DT inferring that the Cascading line tripping being evaluated here is in the “predetermined area” as mentioned in the definition of Cascading?

Requirement R3 simply says “each Transmission station(s) and Transmission substation identified as applicable”. Clarity could be enhanced by stating “…as applicable per Requirements R1 and R4” assuming agreement that Requirement R2 is subsumed by Requirement R1’s use of Attachment 1 (bullet 2.1). All the appropriate Transmission stations and Transmission substations should undergo a risk assessment—simply saying applicable may cause registered entities to inadvertently miss R4 (and possibly R2).

Why would 3.1.2 not be covered in 3.1’s technical rationale?

3.2-Consider using “On-Peak” or “Peak Demand” (defined terms) to describe “System peak” (undefined term). For 3.2.2., consider changing Requirement to say “Applicable Transmission station(s) or Transmission substation(s) that have already been identified as critical to the Interconnection in dynamic or steady state studies do not require any additional studies.” What is the designation or intention associated with” critical" here? Are those Transmission station(s) and Transmission substation(s) that cause instability, Cascading, or uncontrolled separation? Or are part of an IROL? This needs to be clearly delineated within this Standard as the term is used in R5. Consider indicating what is critical in Requirement R5 and reference R5 in 3.2.2—“A Transmission station…..identified as critical using criteria in Requirement R5...”

Format issue with 3.4 and 3.5 which appear to be sub-bullets of 3.3 which, if changed, affects 3.6 references to 3.4 and 3.5.

Should 3.6 say “Protection System” versus “system protection”? Or is the intent “loss of communication for Protection Systems”?

Likes 0	
Dislikes 0	

Response

Jason Snodgrass - Jason Snodgrass On Behalf of: Katrina Lyons, Georgia System Operations Corporation, 3, 4; - Jason Snodgrass

Answer	No
Document Name	

Comment	
GSOC supports comments provided by Georgia Transmission	
Likes 0	
Dislikes 0	
Response	
Zenon O'young-Chu - Seattle City Light - 3	
Answer	No
Document Name	
Comment	
Item 3.1: The requirement is confusingly phrased. “Post-event response” is not a thing of the same type as “amount of acceptable generation loss” and “amount of acceptable load loss”, so it is confusing what kind of technical rationale the requirement is asking for. Also, 3.1.2 seems redundant with this requirement. Item 3.3: Items 3.4, 3.5, and 3.6 seem like they should be sub-requirements to 3.3. Item 3.4: Should exceptions be mentioned for the possible case where a 3-phase fault is not the most severe contingency at the station? Item 3.5: As mentioned in my comments on 3, stations being on the same road does not indicate any additional likelihood of simultaneous faults. Even a fraction of a second difference in fault time makes a difference for transient stability.	
Likes 0	
Dislikes 0	
Response	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
Answer	No
Document Name	
Comment	
PNM and TNMP agree, in part, with EEI comments regarding R3, noted again here. However, aligning with TPL-001 R6 is not acceptable. Entities should define the amount of load and generation loss they will allow for CIP-014 analysis. TPL-001 provides some guidance on load and generation loss in Table 1. *“EEI suggests replacing this requirement and its subparts with language similar to Requirement R6 from TPL-001-5 because the objectives are similar. Additionally, the SAR does not require explicit inclusion of load loss or generation loss limits.*	

o EEI proposes the following language: "Criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding."

o Some Entities may include explicit thresholds in their Cascading criteria or methodology, but other entities define Cascading as a number of successive element losses. The criteria requirement of TPL-001 is sufficient for evaluating transmission system reliability, and similar language should be used in CIP-014.

- R3.1.1 & 3.1.2:

o The purpose of CIP-014 is to protect stations where physical attacks may "result in instability, uncontrolled separation, or Cascading within an Interconnection." The items listed under R3.1.1 may or may not be present in such conditions (e.g., the loss of IBR generation does not directly indicate Cascading risk).

EEI suggests removing 3.1.1, the list of items 3.1.1.1-3.1.1.12, and 3.1.2. This will allow Transmission Owners to define their criteria and methodology. While the list of items provided may add value for consideration, EEI would like to see them moved into the technical rationale for consideration and guidance for Entities during implementation.

Requirement R3, Part 3.2:

- EEI suggests removing "and other System conditions susceptible to instability, uncontrolled separation, or Cascading with an Interconnection" because it requires entities to study conditions other than peak and off-peak.

o Entities may decide to run additional scenarios (e.g., shoulder), but these scenarios should not be included in the requirement language. Additionally, use of the word "any" implies that any System condition that may be susceptible to issues, even if those conditions are sufficiently bounded by the Peak and Off-Peak scenarios are required for analysis, which is overly broad.

- R3.2.1: EEI suggests striking "including any tripped facilities from dynamic simulations." Steady-state and dynamic simulations are performed separately and often done by different parties. Some generator tripping in dynamic simulations may not be appropriate for steady-state to evaluate, for example, an IBR that trips in the dynamic simulation may reconnect shortly after the fault clears, even if this reconnection is not represented in stability simulations. However, it would be appropriate to have the generator reconnected in the steady-state simulation. The wording of R3.2.1 is sufficient without this last clause.

- EEI also seeks clarity on the use of the phrases "deemed as critical" and "classified as critical" in Requirement R3, Part 3.2.2 and Requirement R5, Parts 5.1 and 5.2. It is not clear that the intended result of the risk assessment performed in Requirement R5 is for the TO to deem Transmission station(s) and Transmission substation(s) as critical or non-critical. EEI suggests the following revision for consideration:

R3. Each Transmission Owner shall have a documented risk assessment methodology for ***determining if Transmission station(s) and Transmission substation(s) are critical including*** *evaluating the loss of each Transmission station(s) and Transmission substation(s) identified as applicable. The methodology shall include, at a minimum, the following:*

Requirement R3, Part 3.3, 3.4, & 3.5:

- EEI asks the drafting team to revise Requirement R3, Part 3.3 to allow flexibility for the Transmission Owner to determine appropriate and reasonable study scenarios and study assumptions considering the intent of CIP-014-3 and the potential range of issues during a physical attack. We suggest the following modification to Requirement R3, Part 3.3: **"***Analysis of fault simulations determined to be appropriate and reasonable by the Transmission Owner."*

EEI suggests striking 3.4 & 3.5 and allowing the TO to determine the appropriate study scenarios as described in EEI's proposed revision of Requirement R3, Part 3.3 above. EEI is concerned that the scenarios included in 3.4 & 3.5 have not been justified as appropriate and reasonable as required by the SAR. As an example, there is no historical precedence for a physical attack resulting in a bolted 3-phase fault with loss of all

communications as listed in 3.4. Similarly, it is not clear how a physical attack that only impacts one station produces a 3-phase fault, but an event large enough to impact multiple stations produces a single-phase fault. The technical rationale does not include technical justifications for the selection of these scenarios."	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	No
Document Name	
Comment	
ITC supports the EEI response	
Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 6	
Answer	No
Document Name	
Comment	
Item 3.1: The requirement is confusingly phrased. "Post-event response" is not a thing of the same type as "amount of acceptable generation loss" and "amount of acceptable load loss", so it is confusing what kind of technical rationale the requirement is asking for. Also, 3.1.2 seems redundant with this requirement. Item 3.3: Items 3.4, 3.5, and 3.6 seem like they should be sub-requirements to 3.3. Item 3.4: Should exceptions be mentioned for the possible case where a 3-phase fault is not the most severe contingency at the station? Item 3.5: As mentioned in my comments on 3, stations being on the same road does not indicate any additional likelihood of simultaneous faults. Even a fraction of a second difference in fault time makes a difference for transient stability.	
Likes 0	
Dislikes 0	
Response	

Robert Jones - Seattle City Light - 4	
Answer	No
Document Name	
Comment	
Item 3.1: The requirement is confusingly phrased. “Post-event response” is not a thing of the same type as “amount of acceptable generation loss” and “amount of acceptable load loss”, so it is confusing what kind of technical rationale the requirement is asking for. Also, 3.1.2 seems redundant with this requirement. Item 3.3: Items 3.4, 3.5, and 3.6 seem like they should be sub-requirements to 3.3. Item 3.4: Should exceptions be mentioned for the possible case where a 3-phase fault is not the most severe contingency at the station? Item 3.5: As mentioned in my comments on 3, stations being on the same road does not indicate any additional likelihood of simultaneous faults. Even a fraction of a second difference in fault time makes a difference for transient stability.	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See EEI comments	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
Was the intent to have the responsible entity establish their own “acceptable load loss.” In other cases it is up to the BA, RC, or RP to determine a Facility’s acceptable load loss.	

Requirement 3.3 appears to be missing text and subsections. However, the Technical Rational does include details of this section.

Recommend rewording Part 3.6 to provide clarification on “loss of communication and system protection”. Utilizing the NERC defined term of Protection System could limit interpretation of what a loss of system protection entails. We realize that the drating team may intend to include loss of protection system equipment, but not the Protection System as a whole. Rewording to make this clearer could be beneficial.

Suggest modifying Part 3.1.1.7 to say “Loss of synchronous generation” rather than “loss of IBR generation” for inclusion of other generation types.

Likes 0	
Dislikes 0	

Response

Chris Shultz - Seattle City Light - 5

Answer	No
Document Name	

Comment

Item 3.1: The requirement is confusingly phrased. “Post-event response” is not a thing of the same type as “amount of acceptable generation loss” and “amount of acceptable load loss”, so it is confusing what kind of technical rationale the requirement is asking for. Also, 3.1.2 seems redundant with this requirement.

Item 3.3: Items 3.4, 3.5, and 3.6 seem like they should be sub-requirements to 3.3.

Item 3.4: Should exceptions be mentioned for the possible case where a 3-phase fault is not the most severe contingency at the station?

Item 3.5: As mentioned in my comments on 3, stations being on the same road does not indicate any additional likelihood of simultaneous faults. Even a fraction of a second difference in fault time makes a difference for transient stability.

Likes 0	
Dislikes 0	

Response

Michael Jang - Seattle City Light - 1

Answer	No
Document Name	

Comment

Providing support based on SCL SME's opinion:

Item 3.1: The requirement is confusingly phrased. “Post-event response” is not a thing of the same type as “amount of acceptable generation loss” and “amount of acceptable load loss”, so it is confusing what kind of technical rationale the requirement is asking for. Also, 3.1.2 seems redundant with this requirement.

Item 3.3: Items 3.4, 3.5, and 3.6 seem like they should be sub-requirements to 3.3.

Item 3.4: Should exceptions be mentioned for the possible case where a 3-phase fault is not the most severe contingency at the station?

Item 3.5: As mentioned in my comments on 3, stations being on the same road does not indicate any additional likelihood of simultaneous faults. Even a fraction of a second difference in fault time makes a difference for transient stability.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

NV Energy supports the EEI response to this question.

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1,3,5

Answer	No
Document Name	

Comment

R3 is poorly written but meets the intent of addressing issues identified in the SAR. The requirement as written mixes methodology concepts with criteria for evaluation. Sub-requirement R3.3 does not clearly state how a “fault simulation” is applicable to either dynamic and/or steady state simulations.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	No
Document Name	

Comment	

We are unsure of what “acceptable loss” means in 3.1. Is this a technical term or defined by the entity on a case-by-case basis.

We propose changing “susceptible” to “vulnerable” in Part 3.2.

We noticed that 3.3 seems to be missing text and subsections. The Technical Rational had a section on 3.3.

In Part 3.6 why is “system protection” used instead of the NERC glossary defined term of “Protection System”?

R3.1.1.4 “Relay Loadability” is already factored into R3.1.1.3 “Thermal Loading of Facilities” and should be removed due its duplicative nature.

R3.1.1.7 – This should state “Loss of generation” since loss of synchronous generation as well as IBR generation would both cause concerns.

R3.3 Appears to be missing and does not line up with the information provided in the technical rationale.

Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Eclectic Institute	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
IID recommends numbering be fixed for section 3.3. Technical Rationale refers to section 3.3.1, however there is no 3.3.1 in redlines to approved. Furthermore, IID is unsure if R3 is referring to steady state transient or short circuit.	
Likes 0	

Dislikes 0	
Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	No
Document Name	
Comment	
IID recommends numbering be fixed for section 3.3. Technical Rationale refers to section 3.3.1, however there is no 3.3.1 in redlines to approved. Furthermore, IID is unsure if R3 is referring to steady state transient or short circuit.	
Likes 0	
Dislikes 0	
Response	
James Baldwin - James Baldwin On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - James Baldwin	
Answer	No
Document Name	
Comment	
The list of study requirements is very prescriptive and severe. Compliance risk rises substantially when a standard becomes overly prescriptive and demanding. That risk is compounded by the increase in the number of stations identified in R1 and R2. There is a formatting issue with 3.4 and 3.5.	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	
• Per the NERC Functional Model, the Transmission Owner (TO) is defined as "the entity that owns and maintains transmission Facilities." R3 is addressing analysis criteria and assumptions that are beyond the purview and capabilities of the TO and is not consistent with the TO	

expectations set forth in the referenced NERC Functional model. This includes determining the amount of acceptable load loss, the amount of generation loss, and the evaluation of instability, uncontrolled separation, and Cascading within the Interconnection.
- R3 is misplaced in this CIP standard and should be addressed via a separate project in the TPL space. This project should include SMEs from the planning functions so the appropriate expertise informs potential requirements.
- It is understood that the current version of CIP-014 addresses aspects of the analysis. This construct is problematic as currently written and applied to the TO function.
- Regarding 3.1.1.5: There is no apparent value added by evaluating post-contingency voltage deviation. Steady-state, post-contingency voltage is a problem if the voltage is outside of System Voltage Limits. The post-contingency voltage problem is not dependent on the pre-contingency voltage level nor the deviation from such level.
- Regarding 3.1.1.7 Loss of IBR generation should be changed to "Loss of generation." The amount of generation loss and its impact on the ability of the BES to remain stable and serve load is the concern and is not specific to IBR.
- R3.3 - R3.6 prescribe the analysis of fault simulations. However, the purpose of the standard is to identify and protect transmission stations and transmission substations (and the BPS) from the results of a physical attack. As such, we need to first understand the types of physical attacks we are simulating. (i.e. What type of physical attack would result in a bolted 3-phase fault at only the highest voltage level bus at one station (and potentially another, simultaneously, in proximity per R2), and what type of attack would result in simultaneous single-phase faults at the highest voltage level buses of stations in the close proximity to each other? What does physical security at a particular station do to mitigate the issue?
- Regarding R3.2.2: GTC recommends insertion the word "current" immediately preceding "dynamic or steady state." A transmission station or Transmission substation that is already identified as critical to the Interconnection in **current** dynamic or steady state studies does not require any additional studies during the assessment.
- Regarding 3.6: The requirement for fault simulations to assume all loss of communication and system protection at the Transmission station or Transmission substation should be based on the type of attack being simulated. What type of attack would result in loss of all communication and system protection at the Transmission station or Transmission substation? What does physical security at a particular station do to mitigate the issue?

Likes 0	
Dislikes 0	

Response

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

EEI is generally concerned with the addition of prescriptive requirement language that is not wholly supported by the scope of the SAR. It is important to provide flexibility for various approaches to the risk assessment due to expected differences in each registered entity's facts and circumstances while supporting the intent of CIP-014. EEI proposes the following edits for consideration:

Requirement R3, Part 3.1:

- EEI suggests replacing this requirement and its subparts with language similar to Requirement R6 from TPL-001-5 because the objectives are similar. Additionally, the SAR does not require explicit inclusion of load loss or generation loss limits.

o EEI proposes the following language: "Criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding."

o Some Entities may include explicit thresholds in their Cascading criteria or methodology, but other entities define Cascading as a number of successive element losses. The criteria requirement of TPL-001 is sufficient for evaluating transmission system reliability, and similar language should be used in CIP-014.

- R3.1.1 & 3.1.2:

o The purpose of CIP-014 is to protect stations where physical attacks may "result in instability, uncontrolled separation, or Cascading within an Interconnection." The items listed under R3.1.1 may or may not be present in such conditions (e.g., the loss of IBR generation does not directly indicate Cascading risk).

§ EEI suggests removing 3.1.1, the list of items 3.1.1.1-3.1.1.12, and 3.1.2. This will allow Transmission Owners to define their criteria and methodology. While the list of items provided may add value for consideration, EEI would like to see them moved into the technical rationale for consideration and guidance for Entities during implementation.

Requirement R3, Part 3.2:

- EEI suggests removing "and other System conditions susceptible to instability, uncontrolled separation, or Cascading with an Interconnection" because it requires entities to study conditions other than peak and off-peak.

o Entities may decide to run additional scenarios (e.g., shoulder), but these scenarios should not be included in the requirement language. Additionally, use of the word "any" implies that any System condition that may be susceptible to issues, even if those conditions are sufficiently bounded by the Peak and Off-Peak scenarios are required for analysis, which is overly broad.

- R3.2.1: EEI suggests striking "including any tripped facilities from dynamic simulations." Steady-state and dynamic simulations are performed separately and often done by different parties. Some generator tripping in dynamic simulations may not be appropriate for steady-state to evaluate, for example, an IBR that trips in the dynamic simulation may reconnect shortly after the fault clears, even if this reconnection is not represented in stability simulations. However, it would be appropriate to have the generator reconnected in the steady-state simulation. The wording of R3.2.1 is sufficient without this last clause.

- EEI also seeks clarity on the use of the phrases "deemed as critical" and "classified as critical" in Requirement R3, Part 3.2.2 and Requirement R5, Parts 5.1 and 5.2. It is not clear that the intended result of the risk assessment performed in Requirement R5 is for the TO to deem Transmission station(s) and Transmission substation(s) as critical or non-critical. EEI suggests the following revision for consideration:

R3. Each Transmission Owner shall have a documented risk assessment methodology for **determining if Transmission station(s) and Transmission substation(s) are critical including** evaluating the loss of each Transmission station(s) and Transmission substation(s) identified as applicable. The methodology shall include, at a minimum, the following:

Requirement R3, Part 3.3, 3.4, & 3.5:

- EEI asks the drafting team to revise Requirement R3, Part 3.3 to allow flexibility for the Transmission Owner to determine appropriate and reasonable study scenarios and study assumptions considering the intent of CIP-014-3 and the potential range of issues during a physical attack. We suggest the following modification to Requirement R3, Part 3.3: **"**Analysis of fault simulations determined to be appropriate and reasonable by the Transmission Owner."

- EEI suggests striking 3.4 & 3.5 and allowing the TO to determine the appropriate study scenarios as described in EEI's proposed revision of Requirement R3, Part 3.3 above. EEI is concerned that the scenarios included in 3.4 & 3.5 have not been justified as appropriate and reasonable as required by the SAR. As an example, there is no historical precedence for a physical attack resulting in a bolted 3-phase fault with loss of all communications as listed in 3.4. Similarly, it is not clear how a physical attack that only impacts one station produces a 3-phase fault, but an event large enough to impact multiple stations produces a single-phase fault. The technical rationale does not include technical justifications for the selection of these scenarios.

Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren supports EEI's comments on this project.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO-NSRF and EEI's 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	
MPC concurs with the comments of ACES and the MRO NSRF.	
Likes 0	
Dislikes 0	

Response

Fon Hiew - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	No
Document Name	

Comment

We are unsure of what “acceptable loss” means in 3.1. Is this a technical term or defined by the entity on a case-by-case basis.

We propose changing “susceptible” to “vulnerable” in Part 3.2.

We noticed that 3.3 seems to be missing text and subsections. The Technical Rational had a section on 3.3.

In Part 3.6 why is “system protection” used instead of the NERC glossary defined term of “Protection System”?

R3.1.1.4 “Relay Loadability” is already factored into R3.1.1.3 “Thermal Loading of Facilities” and should be removed due its duplicative nature.

R3.1.1.7 – This should state “Loss of generation” since loss of synchronous generation as well as IBR generation would both cause concerns.

R3.3 Appears to be missing and does not line up with the information provided in the technical rationale.

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	No
Document Name	

Comment

We are unsure of what “acceptable loss” means in 3.1. Is this a technical term or defined by the entity on a case-by-case basis.We propose changing “susceptible” to “vulnerable” in Part 3.2.

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R3.3 Appears to be missing and does not line up with the information provided in the technical rationale.

Likes 0	
Dislikes 0	

Response

Mark Flanary - Midwest Reliability Organization - 10

Answer	No
Document Name	

Comment

Parts 3.4, 3.5, and 3.6 appear to be sub-parts of 3.3 and should be be labeled 3.3.1, 3.3.2, and 3.3.3, respectively.

R3.1: The phrase "post-event response" in this context reduces clarity of the Requirement. The Requirment should clearly set expectations that the criteria for instability, uncontrolled separation, or Cascading within an Interconnection need to be addressed in the risk assessment methodology. Consider removing the phrase "post-event response" to clarify the objective of the technical rationale.

R3.2: The Requirement as written identifies some System conditions for analysis, but is silent on time horizon which can lead to inconsistencies in model usage. Consider clarifying what model year(s) to use (e.g., one year out; two year out; five year out; etc.) or providing a framework for determining model year(s) to use.

R3.5: The rationale for using “single-phase faults at the highest voltage level buses of each of the Transmission station(s) or Transmission substation(s)” for substations that are identified in accordance with Requirement R2 is assuming the best case scenario and results in a weaker study outcome. Consider combining with R3.4 while making R3.4 more general addressing single or multiple (sub)stations to produce a more robust study.

Likes 0	
Dislikes 0	

Response

Jeffrey Streifling - NB Power Corporation - 1

Answer	No
Document Name	

Comment

We are unsure of what “acceptable loss” means in 3.1. Is this a technical term or defined by the entity on a case-by-case basis.

We propose changing “susceptible” to “vulnerable” in Part 3.2.

We noticed that 3.3 seems to be missing text and subsections. The Technical Rational had a section on 3.3.

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R3.1.1.7 – This should state "Loss of generation" since loss of synchronous generation as well as IBR generation would both cause concerns.

R3.3 Appears to be missing and does not line up with the information provided in the technical rationale.

Likes 0	
Dislikes 0	

Response

Dave Krueger - SERC Reliability Corporation - 10

Answer	No
Document Name	

Comment

Thank you for the chance to comment, SERC appreciates the complexity of the SDT's task of modifying multiple parts of such a high profile and high-priority standard.

Item #3.A R3.1.2 states that the R3 documented risk methodology should contain 'Technically supported thresholds for acceptable load loss and acceptable generation loss". Given that no NERC Responsible Entity with applicability to CIP-014-3 comprises the entirety of an Interconnection, the allowance for each individual TO to derive thresholds for what is acceptable at an Interconnection level seems dubious, and likely invites compliance scrutiny. Determining such a threshold may also be beyond the capability of some of the smaller TOs who do not have as wide a view of the planning process. Having consistent implementation of criteria is mentioned in SAR Project Scope Item #3: "*Assure the adequacy and consistent implementation of technically supported justification for study decisions. Clarity should include specificity regarding the documentation, and usage of criteria to identify instability, uncontrolled separation, or Cascading within an Interconnection occur as part of a risk assessment.*" Having this criterion be up to individual interpretation would appear not to fully address that. Suggest instead the use of a common and published criteria, such as NERC's annual Frequency Response Annual Analysis, to provide a consistent reference point for all entities to utilize, at least by default as a compliance "floor". If it was desirable to add flexibility to utilize a more conservative reference point (e.g. a lower threshold of lost Generation MWs for a specific ISO), that could be something defined that in that TO's R3 methodology or a common methodology used by all TO members of an RTO/ISO.

Likes 0	
Dislikes 0	

Response

Teresa Krabe - Lower Colorado River Authority - 5

Answer	No
Document Name	

Comment

The list of study requirements is very prescriptive and severe. Compliance risk rises substantially when a standard becomes overly prescriptive and demanding. That risk is compounded by the increase in the number of stations identified in R1 and R2.

There is a formatting issue with 3.4 and 3.5.

Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP supports the MRO NSRF with Tacoma Power's comments.	
Likes 0	
Dislikes 0	
Response	
Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
AZPS agrees with EEI's comments regarding R3.4 & 3.5. The current draft does not provide rationale to support or justify the prescribed fault simulation parameters. For 3.1.1.7., AZPS does not understand the specific inclusion of IBR generation. This bullet should be removed or justified.	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	No
Document Name	
Comment	

Eversource believes R3.1.1.4 “Relay Loadability” is already factored into R3.1.1.3 “Thermal Loading of Facilities” and should be removed due its duplicative nature.

R3.1.1.7 – This should state “Loss of generation” since loss of synchronous generation as well as IBR generation would both cause concerns.

R3.3 Appears to be missing and does not line up with the information provided in the technical rationale.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy supports EEI comments.

Likes 0	
Dislikes 0	

Response

Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF

Answer	No
Document Name	

Comment

Duke Energy does not agree with the risk assessment language proposed in R3 and does not support the proposed fault simulation language. Simulating a bolted 3-phase fault is not a valid study assumption because it simulates a highly implausible scenario. The drafting team has not demonstrated that this scenario can be created with a physical attack which physical protection can mitigate. This simulation implies a “crater” scenario, but the issue is that even a true crater scenario would be unlikely to cause this type of fault as typically simulated by software platforms such as PSSE. Duke Energy also support EEI concerns on the issue of the bolted 3-phase fault.

For 3.1.1. Duke Energy suggests adding parameters at the end of the parent statement to read “Load loss, generation loss, and post-event response within an Interconnection shall be evaluated, using at a minimum the following **parameters**”. We believe that the list under 3.1.1 is not adequately justified and should be revaluated only to include parameters for evaluation that are directly related to instability, uncontrolled separation, or cascading within an interconnection.

Duke Energy has concern that 3.2 is overly broad in reference to “other system conditions susceptible to instability”, given that all conditions are susceptible to instability and this language could require an excess of system conditions to be analyzed. We support EEI comments on this issue.

The numbering/layout of R3 needs to be revised as R3.4 and R3.5 appear to be sub-requirements of R3.3. Correcting this will also impact how R3.6 is written.

Lastly, Duke Energy requests that the drafting team clarify the use of the word “critical” in the revisions. We infer that critical is meant to represent the sites that have already have been identified as sites that require physical protection under previous CIP-014 analysis, but whether or not this is the intended use is not clear in the present draft.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	No
Document Name	

Comment

Black Hills Corporation agrees with EEI comments that Requirement R3, Part 3.1 be replaced with language similar to Requirement R6 from TPL-001-5 as the objectives are similar, and the sub-requirements of R3.1.1, and R3.1.2 be struck from the requirement. Black Hills Corporation recommends language that would use the same criteria or methodology used in the analysis for System instability conditions within TPL-001-5 studies or studies under FAC-014-3, should be used for CIP-014-3 as it would align with regional requirements or requirements set forth by the Reliability Coordinator.

Black Hills Corporation agrees with remaining EEI comments for the rest of the subsections of Requirement R3.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	No
Document Name	

Comment

Tri-State agrees with the MRO NSRF Submitted Comments

Likes 0	
Dislikes 0	

Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	

NEE support's EEI comments: " EEI proposes the following edits for consideration:

Requirement R3, Part 3.1:

{C}- EEI suggests replacing this requirement and its subparts with language similar to Requirement R6 from TPL-001-5 because the objectives are similar. Additionally, the SAR does not require explicit inclusion of load loss or generation loss limits.

{C}o EEI proposes the following language: "Criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding."

{C}o Some Entities may include explicit thresholds in their Cascading criteria or methodology, but other entities define Cascading as a number of successive element losses. The criteria requirement of TPL-001 is sufficient for evaluating transmission system reliability, and similar language should be used in CIP-014.

{C}- R3.1.1 & 3.1.2:

{C}o The purpose of CIP-014 is to protect stations where physical attacks may "result in instability, uncontrolled separation, or Cascading within an Interconnection." The items listed under R3.1.1 may or may not be present in such conditions (e.g., the loss of IBR generation does not directly indicate Cascading risk).

{C}§ EEI suggests removing 3.1.1, the list of items 3.1.1.1-3.1.1.12, and 3.1.2. This will allow Transmission Owners to define their criteria and methodology. While the list of items provided may add value for consideration, EEI would like to see them moved into the technical rationale for consideration and guidance for Entities during implementation.

Requirement R3, Part 3.2:

{C}- EEI suggests removing "and other System conditions susceptible to instability, uncontrolled separation, or Cascading with an Interconnection" because it requires entities to study conditions other than peak and off-peak.

{C}o Entities may decide to run additional scenarios (e.g., shoulder), but these scenarios should not be included in the requirement language. Additionally, use of the word "any" implies that any System condition that may be susceptible to issues, even if those conditions are sufficiently bounded by the Peak and Off-Peak scenarios are required for analysis, which is overly broad.

{C}- R3.2.1: EEI suggests striking "including any tripped facilities from dynamic simulations." Steady-state and dynamic simulations are performed separately and often done by different parties. Some generator tripping in dynamic simulations may not be appropriate for steady-state to evaluate, for example, an IBR that trips in the dynamic simulation may reconnect shortly after the fault clears, even if this reconnection is not represented in stability simulations. However, it would be appropriate to have the generator reconnected in the steady-state simulation. The wording of R3.2.1 is sufficient without this last clause.

{C}- EEI also seeks clarity on the use of the phrases "deemed as critical" and "classified as critical" in Requirement R3, Part 3.2.2 and Requirement R5, Parts 5.1 and 5.2. It is not clear that the intended result of the risk assessment performed in Requirement R5 is for the TO to deem Transmission station(s) and Transmission substation(s) as critical or non-critical. EEI suggests the following revision for consideration:

R3. Each Transmission Owner shall have a documented risk assessment methodology for **determining if Transmission station(s) and Transmission substation(s) are critical including** evaluating the loss of each Transmission station(s) and Transmission substation(s) identified as applicable. The methodology shall include, at a minimum, the following:

Requirement R3, Part 3.3, 3.4, & 3.5:

{C}- EEI asks the drafting team to revise Requirement R3, Part 3.3 to allow flexibility for the Transmission Owner to determine appropriate and reasonable study scenarios and study assumptions considering the intent of CIP-014-3 and the potential range of issues during a physical attack. We suggest the following modification to Requirement R3, Part 3.3: **"**Analysis of fault simulations determined to be appropriate and reasonable by the Transmission Owner."

{C}- EEI suggests striking 3.4 & 3.5 and allowing the TO to determine the appropriate study scenarios as described in EEI's proposed revision of Requirement R3, Part 3.3 above. EEI is concerned that the scenarios included in 3.4 & 3.5 have not been justified as appropriate and reasonable as required by the SAR. As an example, there is no historical precedence for a physical attack resulting in a bolted 3-phase fault with loss of all communications as listed in 3.4. Similarly, it is not clear how a physical attack that only impacts one station produces a 3-phase fault, but an event large enough to impact multiple stations produces a single-phase fault. The technical rationale does not include technical justifications for the selection of these scenarios. "

Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	

AEPC signed on to ACES comments below:

ACES feels R3.1 and it's sub requirements are too prescriptive and extend beyond what is listed in the SAR. The main goal of the SAR is to ensure the inclusion of dynamic studies in the risk assessment and increase clarity around criteria to identify instability, uncontrolled separation or Cascading. The additional requirements extend beyond the scope of the SAR.

Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No

Document Name	
Comment	

CenterPoint Energy Houston Electric, LLC (CEHE) recommends removing risk assessment methodology part R3.1.1.1. thru R3.1.1.12 as they are not necessary and too prescriptive. Transmission Owners should establish the methodology and what is to be evaluated. Therefore, these details do not need to be included as part of the CIP-014-4 Standard.

CEHE is capable of providing the study details associated with Requirement 3.6; however, this is adding additional compliance burden on Entities, similar to the challenges identified in TPL-001-5. The study would only be required every 36-calendar months, but Entities do not have a method of automating that process. It would be a manual study review for every substation identified, which would be incredibly intrusive and burdensome.

Likes 0	
Dislikes 0	
Response	

Michael Dillard - Austin Energy - 5, Group Name Austin Energy

Answer	No
Document Name	
Comment	

Austin Energy supports MRO's comments. Attached in Question 1.

Likes 0	
Dislikes 0	
Response	

TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	No
Document Name	
Comment	

Southern Indiana Gas and Electric d/b/a CenterPoint Energy Indiana South (SIGE) agrees with removing risk assessment methodology part R3.1.1.1. thru R3.1.1.12 as they are not necessary and too prescriptive. Transmission Owners should establish the methodology and what is to be evaluated. Therefore, these details do not need to be included as part of the CIP-014-4 Standard.

Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	

WAPA concurs with the comments provided by the MRO NSRF. In addition, WAPA also offers that Requirement 3.2 uses the terminology, "and other System conditions…" which creates a situation where an entity may have to "prove the negative" if an auditor feels that "other System conditions" studied by the entity are not sufficient, even if the prescriptive studies mentioned in 3.2 were performed. Recommend stating what is the minimum requirement and avoid the catch-all, ambiguous phrasing.

Requirement R3.4 and R3.5. It is possible that a fault on a lower voltage level bus at a substation is more severe than the highest voltage level bus, so this is an odd way to make this an explicit requirement.

For R3.6, recommend the use of generic, conservative clearing times (or slowest possible), vice actual clearing times which would alleviate a burden for entities with large number of substations to evaluate while still meeting the objective.

With R3.3 stating "as follows," R3.4, 3.5, etc should be sub-requirements under R3.3

Likes 0	
Dislikes 0	
Response	
Karen Demos - NextEra Energy - Florida Power and Light Co. - 3	
Answer	No
Document Name	
Comment	

NextEra/FPL supports EEI's comments

Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

Sub-Requirement 3.6 assumes loss of communication and system protection regardless if the analysis assumes removal of a singular Transmission station or Transmission substation (R3.4), or if the analysis assumes removal of more than one Transmission station or Transmission substation (R3.5). BPA believes a reasonable threat removing a single substation could be severe enough to remove an entire substation and include loss of communication and protection systems, whereas a threat to more than one substation at the same time would more reasonably be targeted at high voltage equipment and not necessarily result in loss of communications or relaying. BPA recommends that Requirement 3.6 only apply to a singular substation analyzed in Requirement 3.4.

BPA recommends sub-requirements 3.4, 3.5, and 3.6 be re-numbered to 3.3.1, 3.3.2, and 3.3.3.

Likes 0	
Dislikes 0	

Response

Leshel Hutchings - AEP - 3

Answer	No
Document Name	

Comment

Comments: **R3 Section 3.1:**

Reword "*Technical rationale for determining the amount of acceptable load loss, the amount of acceptable generation loss, and post-event response resulting in instability, uncontrolled separation, or Cascading within an Interconnection.*"

To proposed language: "*Technical rationale for determining instability, uncontrolled separation, or Cascading with a critical impact to the operation of an Interconnection.*"

This simplifies confusing language. Move the specific language around "amount of acceptable load loss and the amount of acceptable generation loss" to the 3.1.1 criteria. Add "critical impact to the operation of the Interconnection" language directly from the FERC clarification of the March 7 Order to make explicit the purpose of the risk assessment.

R3 Section 3.1.1:

Suggest removing all of the sub bullets under 3.1.1.

3.1.1 is too prescriptive and the list appears to be a random selection of factors that may or may not influence instability, uncontrolled separation, or Cascading. They would not in themselves generally be taken as constituting measures of instability, uncontrolled separation, or Cascading. Instability, uncontrolled separation, or Cascading already define the three factors to consider. The Standard is not designed nor intended to prescribe the methodology for entities. We support R3 requiring TOs to have a documented risk assessment methodology.

The technical rationale for Part 3.1.1 states that "a TO can decide that one or more of the items are not applicable to their location within the interconnection", but if the items are written explicitly in the standard, particularly with language stating "at a minimum", there will be no flexibility given around considering them all.

3.1.1 and 3.1.2 are duplicative. One should be removed – suggest consolidating to "*Technically supported thresholds for acceptable load loss and generation loss*".

Alternatively, they could be split into two separate bullets: *“3.1.1: load loss, 3.1.2: generation loss”.* “Post-event response” does not add clarity and instability, uncontrolled separation, or Cascading covers this.

R3 Section 3.2:

Propose rewording “Analysis at System Peak, Off-Peak Load, and other System conditions,”

To proposed: “Analysis at System Peak, Off-Peak Load, or other System conditions,” or completely removing this section, otherwise this will triple the number of scenarios/cases for entities.

This will triple the number of scenarios. Additionally, “other System conditions” is left undefined.

One of the reasons for changing the compliance timeframe to 36 months was to be consistent with the case building process. Some RTOs like ERCOT provide limited dynamic cases, so this language means it would not be possible to use the RTO cases unless each TO modifies cases to meet the requirements especially “other system conditions susceptible to instability”.

Some entities previously considered sensitivities based on differing future years with projects in or out of service and received positive observations in audits for this approach. The language in the current draft unfortunately would eliminate the potential for that interpretation.

R3 Section 3.2.1:

The placement of 3.2.1 does not make sense here under 3.2. Suggest making its own bullet 3.7.

3.2.1 will lead to significant nonconvergence issues in steady state if applied in the contingency or even if a base case is created with these outages because the appropriate timing delay cannot be reflected. If outages are applied individually and manually post-contingency this will be a significant increase in the burden of the steady state analysis.

R3 Section 3.2.2:

The placement of 3.2.2 does not make sense here under 3.2. Suggest making its own bullet 3.8. Duplicative with 5.1 – suggest removing 5.1 or at least one of them.

R3 Section 3.3:

Sections 3.4, 3.5, and 3.6 should be sub-bullets to section 3.3, and therefore renumbered to 3.3.1, 3.3.2, and 3.3.3 (3.6.1 would become 3.3.3.1).

Consolidate 3.4 and 3.5 propose 3 phase bolted faults for all events as worst case “smoking crater” scenario.

This reduces complexity of considering different events for one applicable station outages or multiple proximate station outages.

R3 Section 3.6.2 :

Remove 3.6.2.

What value does having this bullet explicitly in the standard add? It will add significant additional compliance burden for evidence to mitigate minor risk and minor result impact.

It should be noted that the risk assessment is performed on future planning cases, and many factors could impact the actual clearing times prior to the dates that the cases represent. Some facilities in the risk assessment will be future/planned stations and without actual clearing times available.

Likes 0	

Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Insitute (EEI) and MRO NSRF for question #4.

Likes 0	
Dislikes 0	

Response

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB

Answer	No
Document Name	

Comment

TVA does not agree with the modifications made in CIP-014-4 with the new Requirement R3.

Regarding R3.4, only one threat level is specified when there are no additional substations included due to proximity. “If the Transmission station(s) or Transmission substation(s) identified in accordance with Requirement R1 is a singular Transmission station or Transmission substation, then fault simulations shall include a bolted 3-phase fault at the highest voltage level bus.”

If only one threat level is suggested to be studied for these events, then it removes the need for an independent verifier. If the event specificity remains, TVA suggests removing the independent verifier requirement.

However, the study parameters of only one threat level for these events is unreasonable and not technically supported by any physical attack risk study that includes the probability of such an attack. If such a study were performed, TVA is confident that a study of one threat level would be shown to be unrealistic. The proposed event is generally considered to be even more severe than a “smoking hole” event. The consequence of having such an unreasonable and overly conservative threat level is the potential for a significant number of additional substations being identified as critical. Protective DCB relaying would not be able to mitigate this type of event as it is written. Since this type of threat cannot typically be mitigated by grid enhancements, a huge expense would be directed to building fences instead of potential improvements to grid reliability. The resulting fences or walls around multiple substations would only draw more attention to those who wish to attack the system. There are ways to still attack the substations, even with the fences, and the result would be a situation with less grid security coupled with a huge unproductive expense.

TVA proposes an approach to consider historical events:

The first step of the methodology would be to do a thorough study of all historical events to identify a series of unique threat vectors. A potential list of identified threat vectors based on historical events might look like:

1) Large transformer banks under gunfire from gunman, firing 100 to 150 rounds of rifle ammunition

2) Total loss of communication prior to event

3) Attacks cut the underground telecommunication fiber optic cables but did not fully disrupt the telemetry between the PG&E substation and the control center.

4) No faults caused by the attack.

4b) Single phase faults caused by the attack.

5) Were fires in the control building or elsewhere in the switchyard? (Y/N)

6) Was power lost in the switchyard? (Y/N)

The second step of the methodology would be to define events to study. Each event would combine several different threat vectors, but NOT at the same time (unless historically verified to happen).

Two Examples of realistic events to study (events that are worse than all historical events, but are not the combination of all possible threats):

1) Study the loss of all power at the substation combined with the loss of all communications at the substation combined with a single phase to ground fault at the highest voltage level (or at all voltage levels). No local breakers operate so that the single phase-phase fault must be cleared remotely from each of the remote substations.

2) Study a 3-phase fault event with the loss of all power at the substation but with communications at the substation still functioning. No local breakers operate so that the 3-phase fault must be cleared remotely from each of the remote substations.

If the CIP-014 methodology included the study of event scenarios like these, then all the attack vectors could be included in the study in a reasonable way. The study events could be designed to be worse than any single historical physical attack scenario that has ever occurred. An overly conservative methodology (that is not based on realistic probabilities) would be a significant time burden to the industry. Expense and grid security potentially would be even worse as a result.

Regarding 3.2.1, adding tripped generators and other tripped facilities from the dynamic stability study to the steady-state contingency definition would create overly conservative results and be excessively burdensome. Often stability studies need to be rerun during the checking process. Any reruns may cause the steady state studies to also be redone. Historically, both studies have been done in parallel and not sequentially. Steady-state studies typically assume constant power loads where power does not vary with changes in voltage magnitude. This is a valid assumption for steady state studies but in reality, loads do not behave this way and differs greatly from how loads are represented in dynamic studies.

From a dynamic studies perspective, the composite load model (CMLD) has seen increased adoption among utilities and more accurately reflects the aggregate behavior of motors. The model includes parameters which dictate fractions of the motor load components that do not restart, even if voltage recovers above the undervoltage trip thresholds. There is currently no industry consensus on whether this fraction of non-restartable motor loss is consequential or non-consequential load loss. TVA's position is that this is consequential load loss, as it's impossible to prevent, would occur for normally cleared faults due to typical undervoltage time delays of 2-3 cycles. Consequential load loss is commonly excluded from steady-state load loss criteria.

To be consistent, there are aspects of the dynamics studies that would also need to be included in the steady state studies to properly align the studies that cannot be readily captured or communicated, such as the amount of load that trips offline (consequentially by the load model). These are quantities that are internal to the simulation that are often unavailable using the apps supplied by PSSE. The complexity of the resulting combined study would be very burdensome and impractical to manage. Therefore, including tripped generators and other tripped facilities from the stability study into the steady-state study could only make sense if loads were also reduced by the fraction of loss. This would be a time burden to the industry as there is currently no practical way to achieve this with the tools available to Transmission Planners. TVA suggest to remove the "including any tripped facilities from dynamic simulations" language.

Likes 0	

Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	

The subparts of R3.1 are very prescriptive and go significantly beyond the requirements listed in the SAR. One of the primary goals of the SAR was to ensure the inclusion of dynamic studies in the risk assessment and increase clarity around criteria to identify instability, uncontrolled separation or Cascading. The draft goes significantly beyond this, requiring prescriptive technical considerations using criteria not mentioned anywhere in the SAR.

In addition, the drafted R3.6 requires the loss of communication and system protection and the station(s) or substation(s) being studied. Entities have multiple means of communications between relays to clear faults, including powerline carrier, microwave and fiber. Faults are typically cleared in 3-5 cycles (.05-.083 seconds). Gunfire cannot cause this complete outage of all communications before the relays can save the system. For the Metcalf attack many years ago that prompted CIP-014, an attacker entered a communications vault outside the substation and cut communications cables. It is very unlikely an attacker can cut the redundant communication circuits used by relays to communicate between substations or within a substation. The SAR only asks for clarification around the use of delayed clearing in study assumptions, and does not mandate its inclusion as its own sub-requirement.

The MRO NSRF recommends that R3 eliminate the prescriptive sub-parts in 3.1, instead requiring the entity to document its criteria, parameters, and study decisions or assumptions in a study methodology, which must include dynamic and steady-state studies. R3 should also include the consideration of physical proximity criteria within the entity's methodology as outlined in Q4. In addition, the MRO NSRF recommends the removal of R3.6. R3 should include only the minimum specifications listed in the SAR.

Finally, the MRO NSRF recommends that entities design their CIP-014 risk assessment methodology with the focus on realistic and likely threat scenarios.

Administratively, given the colon at the end of R3.3, R3.4 thru 3.6 should be numbered 3.3.1 thru 3.3.3. And then, 3.6.1 should be 3.3.3.1 and 3.6.2 be 3.3.3.2.

Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	No
Document Name	
Comment	

- R3 should specify what applicable stations that should be covered in the methodology. Suggest that CIP-014-4 R3 be worded to state: "…loss of each Transmission station(s) **and/**or Transmission substation(s) identified as applicable **in the list established in R1, the criteria developed in R2, and/or the individual or joint responsibilities identified in R4**."
- The wording in R3.1 states that the "…methodology shall include, at a minimum, the following:" which supposes that each area has limits for all of the items listed in R3.1, R3.1.1, and R3.1.2. For example, if an area does not have a limit for loss of load they could be found as non-

compliant. Suggest that this be worded to state:
"…methodology shall **consider**, at a minimum, the following. If one of the following criteria is not utilized in the methodology a technical rationale must be documented."

- In R3.1 I suggest that the wording in the second line be updated to the following "…and **acceptable** post-event **system** response **that results in** instability, uncontrolled separation or Cascading…" to identify what response is being evaluated, and that the intent of the evaluation is to determine an acceptable level of performance.

- In R3.1.1 the use of the phrase "…shall be evaluated…" will compel an entity to evaluate each of the listed items, even though it may not be something that is limiting in that area. Suggest that this section be reworded:
"3.1.1. Load loss, generation loss, and post-event **system** response within an Interconnection shall **be considered and documented technical rationale, for** at a minimum the following:"
- In R3.1.2 the phrase "Technically supported…" can be read in different ways. Suggest rewording:
"**Thresholds for** acceptable load loss and acceptable generation loss **with documented technical rationale**."
- When discussing generator and load loss does the standard allow for entities to define limits as gross OR net loss as they see fit? R3.1.2 lists them separately and it is not clear if they can be assessed simultaneously, if desired.

- The use of the language "…and other System conditions…" could compel an entity to create additional scenarios on top of peak and off-peak that may not be impactful in order to comply with the standard. Suggest this be reworded to the following:
"…Off-Peak Load, and other **optional** System Conditions…"
- R3.2.1 states that "Steady state analysis shall include the removal of all elements that Protection Systems…are expected to automatically disconnect…" but no such specificity is included for dynamic studies that are briefly mentioned at the end of R3.2.1. The TPL-001-5 standard does include such specificity in its R3.3.1 (steady state) and R4.3.1 (dynamics).

- The TPL-001 standard uses the term "stability" whereas the updated CIP-014 uses the term "dynamic"; is there an intended differentiation?
- Is R3.2.2 intended to allow for a station to never be retested in future assessments if it has ever been identified as critical in a previous CIP-014 assessment, or is this requirement intended to permit an entity to not perform both analyses (steady-state and dynamic) if a station is found to be critical in one analysis in the current assessment? Having an entity operating under the assumption that once a station is critical it will always be critical could lead to inefficient response during an event.
- Should R3.4, R3.5, and R3.6 be moved under R3.3 as R3.3.1, R3.3.2, and R3.3.4? In addition, in the existing R3.4 the phrasing is not clear and can potentially be misinterpreted to read that if there was a single substation identified on the R1 list that the testing should be done with a 3LG fault. Suggest that it be reworded:
"**Fault simulations on** Transmission station(s) or Transmission substation(s) identified in accordance with Requirement R1 **that do not include additional proximal facilities** shall include a bolted 3-phase fault at the highest voltage level bus."
- In R3.5 the standard uses the term "If…" when referencing stations identified in R2; but I believe that the intent of R2 is to create groups of proximal stations, so there will always be 2 stations included under the analysis in R3.5 so "If" should be removed.

- R1 refers to creating a list of stations using Attachment 1 of which Criterion 2.1 can identify multiple facilities. However, R3.4, references singular stations and R3.5 refers to the stations added through R2. When read together it is not clear the fault type that should be utilized when testing stations that are identified in Attachment 1 Criterion 2.1. I believe that the testing should include testing of proximal stations individually if they are meeting applicability, and then another simulation that includes testing simultaneous loss of the applicable station and proximal sites.
- In R3.6 the term "…system protection…" is used and not "…protection systems…" as is written in R3.2.1. Is the wording change between R3.2.1 and R3.6 intentional? If so, what is the difference intended to communicate?
- In R3.6.1 the use of the wording "Delayed (remote)…" is not clear. This could be interpreted identify remote clearing that is further delayed by some phenomena, or to only allow for testing through delayed elements and not an overreaching low time delay pilot scheme like a blocking scheme. Suggest that the wording be changed so that it requires entities to assess it based on the clearing times that would be in effect if all protection system at the station(s) under test were disabled.

Likes 0	
Dislikes 0	

Response

Michele Tondalo - United Illuminating Co. - 1	
Answer	No
Document Name	
Comment	

Comment 9: R3 should specify what applicable stations that should be covered in the methodology. Suggest that CIP-014-4 R3 be worded to state:

"…loss of each Transmission station(s) and/or Transmission substation(s) identified as applicable in the list established in R1, the criteria developed in R2, and/or the individual or joint responsibilities identified in R4."

Comment 10: The wording in R3.1 states that the "…methodology shall include, at a minimum, the following:" which supposes that each area has limits for all of the items listed in R3.1, R3.1.1, and R3.1.2. For example, if an area does not have a limit for loss of load they could be found as non-compliant. Suggest that this be worded to state:

"…methodology shall consider, at a minimum, the following. If one of the following criteria is not utilized in the methodology a technical rationale must be documented."

Comment 11: In R3.1 I suggest that the wording in the second line be updated to the following "…and acceptable post-event system response that results in instability, uncontrolled separation or Cascading…" to identify what response is being evaluated, and that the intent of the evaluation is to determine an acceptable level of performance.

Comment 12: In R3.1.1 the use of the phrase "…shall be evaluated…" will compel an entity to evaluate each of the listed items, even though it may not be something that is limiting in that area. Suggest that this section be reworded:

"3.1.1. Load loss, generation loss, and post-event system response within an Interconnection shall be considered and documented technical rationale, for at a minimum the following:"

Comment 13: In R3.1.2 the phrase "Technically supported…" can be read in different ways. Suggest rewording:

"Thresholds for acceptable load loss and acceptable generation loss with documented technical rationale."

Comment 14: When discussing generator and load loss does the standard allow for entities to define limits as gross OR net loss as they see fit? R3.1.2 lists them separately and it is not clear if they can be assessed simultaneously, if desired.

Comment 15: The use of the language "…and other System conditions…" could compel an entity to create additional scenarios on top of peak and off-peak that may not be impactful in order to comply with the standard. Suggest this be reworded to the following:

"…Off-Peak Load, and other optional System Conditions…"

Comment 16: R3.2.1 states that "Steady state analysis shall include the removal of all elements that Protection Systems…are expected to automatically disconnect…" but no such specificity is included for dynamic studies that are briefly mentioned at the end of R3.2.1. The TPL-001-5 standard does include such specificity in its R3.3.1 (steady state) and R4.3.1 (dynamics).

Comment 17: The TPL-001 standard uses the term "stability" whereas the updated CIP-014 uses the term "dynamic"; is there an intended differentiation?

Comment 18: Is R3.2.2 intended to allow for a station to never be retested in future assessments if it has ever been identified as critical in a previous CIP-014 assessment, or is this requirement intended to permit an entity to not perform both analyses (steady-state and dynamic) if a station is found to be critical in one analysis in the current assessment? Having an entity operating under the assumption that once a station is critical it will always be critical could lead to inefficient response during an event.

Comment 19: Should R3.4, R3.5, and R3.6 be moved under R3.3 as R3.3.1, R3.3.2, and R3.3.4? In addition, in the existing R3.4 the phrasing is not clear and can potentially be misinterpreted to read that if there was a single substation identified on the R1 list that the testing should be done with a 3LG fault. Suggest that it be reworded:

"Fault simulations on Transmission station(s) or Transmission substation(s) identified in accordance with Requirement R1 that do not include additional proximal facilities shall include a bolted 3-phase fault at the highest voltage level bus."

Comment 20: In R3.5 the standard uses the term "If…" when referencing stations identified in R2; but I believe that the intent of R2 is to create groups of proximal stations, so there will always be 2 stations included under the analysis in R3.5 so "If" should be removed.

Comment 21: R1 refers to creating a list of stations using Attachment 1 of which Criterion 2.1 can identify multiple facilities. However, R3.4, references singular stations and R3.5 refers to the stations added through R2. When read together it is not clear the fault type that should be utilized when testing stations that are identified in Attachment 1 Criterion 2.1. I believe that the testing should include testing of proximal stations individually if they are meeting applicability, and then another simulation that includes testing simultaneous loss of the applicable station and proximal sites.

Comment 22: In R3.6 the term "…system protection…" is used and not "…protection systems…" as is written in R3.2.1. Is the wording change between R3.2.1 and R3.6 intentional? If so, what is the difference intended to communicate?

Comment 23: In R3.6.1 the use of the wording "Delayed (remote)…" is not clear. This could be interpreted identify remote clearing that is further delayed by some phenomena, or to only allow for testing through delayed elements and not an overreaching low time delay pilot scheme like a blocking scheme. Suggest that the wording be changed so that it requires entities to assess it based on the clearing times that would be in effect if all protection system at the station(s) under test were disabled.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	No
Document Name	

Comment

The draft standard seems to have three scenarios where a station or stations would need to be studied:
1. An individual station meeting the applicability requirements of Attachment 1 (R1 & Attachment 1, part 2).

2. Multiple stations that individually are not applicable but are applicable when combined (R1 & Attachment 1, part 2.1).

3. Multiple stations with one station that is individually applicable based on R1 and additional stations in close proximity to the first (R2).

Scenario 1 would be tested with a three-phase fault per Part 3.4.
Scenario 3 would be tested with a single-line-to-ground fault per Part 3.5.

However, how should Scenario 2 be tested? Since scenario 2 would be identified by R1, Part 3.4 would apply. But Part 3.4 indicates that it only applies to a singular station (emphasis added).

For faults applied in Requirement R3, Parts 3.4 and 3.5, with actual clearing times used, should the standard address how to handle faults that are not fully cleared or do not outage the entire station?

For example, if a three-phase fault is applied per part 3.4, it could be possible that the relaying of remote breakers on some or all of the lower voltage lines may not be able to see the fault on the highest voltage bus through the transformation, leaving a permanent fault on the system. Should the standard discuss propagation of an uncleared fault to lower voltage level(s)? For example, for a similar type of study, NPCC Document A-10, Section 3.5, Step 1b and Technical Rationale 4 discusses the process of propagating uncleared faults through transformers.

In another example, if a single substation (with all equipment within a single fenced enclosure) has multiple voltage levels that are not connected by transformation, with a three-phase fault applied as per part 3.4, the highest voltage facilities would likely be fully cleared by remote lines, but the lower voltage bus(es) would likely remain energized by some or all source lines. Should faults with stations with multiple, separated voltage levels be simulated like adjacent station as per Part 3.5?

Likes 0	
Dislikes 0	

Response

Tyler Schwendiman - ReliabilityFirst - 10

Answer	No
Document Name	

Comment

For 3.1.1, while the listed categories are a good starting point, the list will lead to confusion for both development of the required methodology and audit of that methodology. Some of the categories presented could be applicable to steady-state analysis, dynamic analysis, or both. It is suggested to reference a table rather than list these categories randomly.
For 3.1.1.4, another consideration is that some of the categories overlap or have a relationship with one another (e.g., 'Relay loadability' is a typical factor that contributes to 'Thermal loading of facilities'). It might be better suited to identify the need to consider relay loadability when determining thermal loading or tripping thresholds of transmission elements).
For 3.1.1.7, suggest the removal of 'Loss of IBR generation' since this is already required from the verbiage in 3.1 (i.e., "the amount of acceptable generation loss"). This category could lead to misinterpretation of the requirement to include a more detailed analysis using electromagnetic transient analysis, which is presently not feasibly from a wide-area perspective.
For 3.1.1.11, More clarity is required around this category. Cascading line tripping can be interpreted differently depending on the background and capability of the person performing the analysis and the data available. To some, cascade is a steady-state analysis based on thermal loading above some prescribed level (i.e., 125% of the applicable summer emergency rating). This is in alignment with the idea that the event takes place over a 5-15 min time interval, where conductors are given time to heat up and subsequently trip taking into account the thermal time constants associated with conductors and line ratings. An alternative perspective is immediate cascade tripping for loading outside of a zone 3 relaying scheme, or some type of other protective relaying mechanism tripping the line. This level of relay modeling is not typical in the industry, but more of a best practice. It would be difficult to audit this consistently if this is not a standard practice/capability.

For 3.2, the verbiage, “other System conditions” is ambiguous and should be restated to “at the minimum, one stress scenario”. The stress scenario should also be clearly defined in the required methodology. In addition, 3.2 does not provide any guidance on the year of study (e.g., one year out, two, five, etc.).
For 3.2.1, the stipulation, “including any tripped facilities from dynamic simulations”, seems more like it should be a best practice rather than a requirement. Taking 3.2.1 as written, simulating a substation outage, plus multiple elements that were identified as tripping in dynamic analysis has a higher likelihood of causing a non-convergent solution in steady-state analysis. More clarification is required here in the language to ensure the intent of the requirement is met.
For 3.5, what is the rationale here? If the intent is to simulate a “smoking hole” in 3.4, then the likelihood of debris from the initial attack would result in a single-phase fault at an adjacent substation. It would make more sense to apply a three-phase fault to the first substation, then a single-phase fault to the second.

Likes 0	
Dislikes 0	

Response

Lucinda Bradshaw - Oncor Electric Delivery - 1 - Texas RE

Answer	No
Document Name	

Comment

Oncor disagrees with the modifications in new R3 for the following reasons:

- Thermal overload by itself is not an essential criterion for determining station criticality assuming relay loadability is not exceeded. Oncor suggests removal of thermal loading as a criterion. Thermal loading should be monitored to determine if relay loadability is exceeded.
- “Loss of IBR generation” needs to be clarified as to whether the phrase is referring to consequential or non-consequential generation loss. Additionally, positive-sequence simulations poorly represent actual frequency variations. Frequency calculations can lead to large, unrealistic spikes during faults that may lead to false IBR tripping.
- Frequency exceeding generator limits. As mentioned above, IBR generator tripping could be a result of poor IBR modeling and/or inaccurate frequency calculations in positive-sequence simulations.
- The requirements for the Steady-state volage stability analysis need to be clarified.
- R3.1 and R3.1.2 need to be revised so that the differences between the two sub-requirements are clear.
- The applicable system conditions mentioned in R3.2 need to be defined. Specifically for other system conditions susceptible to instability.
- R3.6.1 and R3.6.2 need to be revised so that the differences between the two sub-requirements are clear.

Likes 0	
Dislikes 0	

Response

Kelley Sargent - Puget Sound Energy, Inc. - 3

Answer	No
Document Name	

Comment	
It may be difficult for a utility to define interconnection level thresholds for acceptable load loss and acceptable generation loss (under R3.1.2), which may be better understood and specified by a regional planning authority. It will be helpful if the standard defines the thresholds for acceptable load/generation loss (under R3.1.2), that will differentiate smaller level local impact (non-critical) from an interconnection level widespread impact (critical).	
Likes 0	
Dislikes 0	
Response	
Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova	
Answer	No
Document Name	
Comment	
While dynamic studies may be suitable to determine the criticality of a bus/station, the methodology described in R3 is too onerous on such a standard. CIP-014 is its own standard and should not require repetition of the dynamic studies under the scope of other standards. Performing base case preparation and performance criteria etc. are not suitable for physical security standard. System criticality is already being identified in other NERC standards/requirements. RC's have accountability and oversight into system criticality and the various types of dynamic studies being listed under R3. (It is not within the accountability of the TO's in many jurisdictions). In addition, the *technical rationale document* implies that it's up to the TO to determine which studies are applicable which makes interpretation of the standard confusing. Much of the criteria proposed in R3 are not under the purview or overnight of an individual TO.	
Likes 0	
Dislikes 0	
Response	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO, Group Name Manitoba Hydro Group	
Answer	No
Document Name	
Comment	

MH believes that R3.1 is too prescriptive and goes beyond what is expected in the SAR. It is recommended to either remove these details or move them to an attachment as technical guidance. The drafting team didn't mention the use of the under-frequency and/or under-voltage load shed relays, which are important for determining load loss.

MH also suggests making the format change where R3.4-R3.6 should be R3.3.1-R3.3.3.

Likes 0	
Dislikes 0	

Response

Rebika Yitna - Rebika Yitna On Behalf of: Roger Brand, MEAG Power, 3, 1; - Rebika Yitna

Answer	No
Document Name	

Comment

R3 as written is too prescriptive, goes beyond the requirements of the SAR, and limits the flexibility of entities to define and carry out their own risk-based risk assessment methodology based on the unique characteristics of their system(s).

Likes 0	
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Tacoma Power supports the MRO NSRF comments, as follows.

The subparts of R3.1 are very prescriptive and go significantly beyond the requirements listed in the SAR. One of the primary goals of the SAR was to ensure the inclusion of dynamic studies in the risk assessment and increase clarity around criteria to identify instability, uncontrolled separation or Cascading. The draft goes significantly beyond this, requiring prescriptive technical considerations using criteria not mentioned anywhere in the SAR.

In addition, the drafted R3.6 requires the loss of communication and system protection and the station(s) or substation(s) being studied. Entities have multiple means of communications between relays to clear faults, including powerline carrier, microwave and fiber. Faults are typically cleared in 3-5 cycles (.05-.083 seconds). Gunfire cannot cause this complete outage of all communications before the relays can save the system. For the Metcalf attack many years ago that prompted CIP-014, an attacker entered a communications vault outside the substation and cut communications cables. It is very unlikely an attacker can cut the redundant communication circuits used by relays to communicate between substations or within a substation. The SAR only asks for clarification around the use of delayed clearing in study assumptions, and does not mandate its inclusion as its own sub-requirement.

The MRO NSRF recommends that R3 eliminate the prescriptive sub-parts in 3.1, instead requiring the entity to document its criteria, parameters, and study decisions or assumptions in a study methodology, which must include dynamic and steady-state studies. R3 should also include the consideration of physical proximity criteria within the entity's methodology as outlined in Q4. In addition, the MRO NSRF recommends the removal of R3.6. R3 should include only the minimum specifications listed in the SAR.

Finally, the MRO NSRF recommends that entities design their CIP-014 risk assessment methodology with the focus on realistic and likely threat scenarios.

Administratively, given the colon at the end of R3.3, R3.4 thru 3.6 should be numbered 3.3.1 thru 3.3.3. And then, 3.6.1 should be 3.3.3.1 and 3.6.2 be 3.3.3.2.

Likes 0	
Dislikes 0	

Response

Kevin Conway - Western Power Pool - 4

Answer	No
Document Name	

Comment

R3 is essentially a fill-in-the-blank requirement that may have a list of "check-box" topics. Entities will only strive to meet the minimum expectations of the stated requirement, since going above and beyond will only expose them to more risk. These types of requirements also cause auditors to audit quality, not objective performance. This will be enforced as a zero defect standard, because the entity will miss a "check-box" item, or the auditor will not agree that the entity addressed the subject to their personal satisfaction. Ideally the list should include how much load loss and expected performance metrics that all entities must meet.

Likes 0	
Dislikes 0	

Response

Matt Carden - Southern Company - Southern Company Services, Inc. - 1

Answer	No
Document Name	Attachment 1.docx

Comment

Southern Company agrees with the need for detailed requirements for fault simulations provided in Requirement R3.3, but there is need for some additional clarification or modification of R3.4 and R3.5 based on the assumptions detailed in R3.6.

As written, an unintended consequence of R3.4 would be ambiguity in how to simulate events for transmission stations or transmission substations with multiple voltages. For example, in Figure 1 below, R3.4 would require the placement of a bolted 3-phase fault at the 500kV bus. A clarification is needed in R3.6 on if the loss of communication and protection needs to be assumed for just the highest voltage level bus (i.e. 500kV bus in this exmample) of the transmission subsation(s). If the intent is to cover all voltage levels, the 115kV System in this example would rely on breakers at remote stations H, I, and J to clear the fault (based on assumptions outlined in R3.6). Additional assumptions of the simulated event not provided in Requirement R3 would need to be made since those stations may or may not clear for the initial fault at the 500kV bus of study. This could lead to inconsistency in analysis.

See Attachment 1 for figure 1.

Additionally, the fault simulations could vary greatly between a singular substation with multiple voltages and multiple substations with multiple voltages for the same event. In Figure 2, R3.5 would require simulation of simultaneous single line to ground faults at the 500kV and 115kV buses for a nearly identical event as Figure 1 (assuming physical proximity of the two events is also similar).

See attachment 1 for figure 2.

Southern Company recommends simplifying the simulations required to include faults at all voltage level buses of the applicable transmission station(s) or substation(s). This would provide clarity for what should be simulated and avoid excessively complex simulations for the assessment.

Southern Company recommends removing “and other System conditions” from Requirement R3.2. The inclusion of other System conditions could lead to varying interpretations and expectations regarding the assessment requirements.

Likes 0	
Dislikes 0	

Response

James Keele - Entergy - 3

Answer	No
Document Name	

Comment

part that gives me concern, is some of the specific language proposed in R3 (see below) that could change the way we are doing the assessment and cause impacts to the potential changes or even increase the current list. Item 3.6 is probably most concerning to me and want to make sure we are effectively reviewing that info with the SME’s and providing comments back to the drafting team if it has negative consequences for us.

3.2.1.Steady state analysis shall include the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event, including any tripped facilities from dynamic simulations.

3.2.1. Adding tripped generators from the dynamic stability study to the steady-state contingency definition would create overly conservative results. Historically, both studies have been done in parallel and not directly informed each other.

Steady-state studies typically assume constant power loads where power does not vary with changes in voltage magnitude. This is a valid assumption for steady state studies but in reality, loads do not behave this way and differs greatly from how loads are represented in dynamic studies.

For dynamic studies the composite load model (CMLD) has seen increased adoption among utilities and more accurately reflects the aggregate behavior of motors. The model includes parameters which dictate fractions of the motor load components that do not restart, even if voltage recovers above the undervoltage trip thresholds. There is currently no industry consensus on whether this fraction of non-restart able motor loss is consequential or non-consequential load loss. Entergy's stance is that this is consequential load loss as it's impossible to prevent and would occur even for normally cleared faults due to typical undervoltage time delays of 2-3 cycles. Consequential load loss is commonly excluded from steady-state load loss criteria.

In summary, reflecting tripped generators from the stability study to the steady-state study would only make sense if loads were also reduced by the fraction of non-restart able motor loss. This would be extremely tedious as there is currently no practical way to achieve this with the tools available to Transmission Planners. There may be other issues that may need to be considered. Removal of the "including any tripped facilities from dynamic simulations" language should be considered.

3.6. Fault simulations shall assume the loss of communication and system protection at the Transmission station(s) or Transmission substation(s) studied under Requirement R3, Parts 3.4 and 3.5.

3.6.1. Delayed (remote) clearing times shall be used unless otherwise technically substantiated.

3.6.2. Actual clearing times shall be used unless otherwise technically substantiated.

3.6 Existing language may lead to multiple interpretations at stations with multiple control houses. Although the standard doesn't specifically mention control houses, a total loss of communication and system protection would likely be the result of control house being damaged/destroyed.

{C}· One interpretation could be that the loss of a single control house satisfies the considering the "loss of communication and system protection at the Transmission station(s) or Transmission substation(s) requirement" language. The existence of a second control house would then be used as the technical basis [3.6.1.] as to why you wouldn't have delayed clearing on some elements.

{C}· Another interpretation could be to assume the loss of all communication and system protection which means all the control houses at the Transmission station(s) or Transmission substation(s) are destroyed.

Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	

R3 is poorly written but meets the intent of addressing issues identified in the SAR. The requirement as written mixes methodology concepts with criteria for evaluation. Sub-requirement R3.3 does not clearly state how a "fault simulation" is applicable to either dynamic and/or steady state simulations.

Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No

Document Name	
Comment	
Need clarification on R3.1.1.8 “Frequency exceeding generator limits”. R3.2.2: implies once a site is deemed critical, it remains critical. There needs to be a process to remove stations from critical list if in future assessments it is deemed non-critical. As written, R3.4, R3.5, and R3.6 should be sub requirements of R3.3.	
Likes 0	
Dislikes 0	
Response	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1 - RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
While we agree that the modification meets the intent of the SAR, in sub-requirement R3.4 uses the term “”bolted 3-phase fault”. This is inconsistent with other NERC standards. We suggest simply using the term 3-phase fault.	
Likes 0	
Dislikes 0	
Response	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	Yes
Document Name	

Comment	
Requiring TOPs to have a documented risk assessment methodology for evaluating their applicable stations and establishing the minimum methodology requirements helps to address the issues identified in the SAR. However, the list of mandatory criteria under R3.1. is quite prescriptive; these sorts of standard practices are to be avoided, to be better suited under technical guidance. There is no precedence for this level of specificity in any other NERC study performance standard to our knowledge. Furthermore, NERC has failed to provide a rationale behind why all of these criteria are critical to be included in the assessment and analysis. Additionally, in R3.2, there is a term '**other System conditions susceptible to** instability, uncontrolled separation, or Cascading within an Interconnection' (emphasis added). This is vague and undefined; the expectation is not clear, and this is a case of chicken-and-egg – one cannot know such an outcome unless one has run a study, but one would not run such a study unless one already knew that a particular condition was susceptible. It is recommended this language be removed. System peak and System Off-Peak are common terms in TPL-001-5 and are supported as adequate indicators. NERC may consider these being the required minimum study conditions, but open the door to such things as the 'other System conditions susceptible to'… as optional studies, or mandatory if requested by an RC, PC, etc (similar to the selection criteria of stations – moving that concept to the conditions to be studied as well). Further, the modification in R3.2.2. regarding stations that have been identified as critical makes it unclear how or if a station may be "un-identified". For example, if a CAP speeds up clearing times for loss of communication times and this prevents an identified instability, could the analysis be re-run and the station re-categorized? This is unclear with the new language proposed in R3.2.2. It does not appear that such instances of de-listing a station have been contemplated. As a piece of minor editorial recommendation; the sections 3.4, 3.5, and 3.6 following R3.3 are functionally sub-requirements of R3.3. It is recommended these be treated as R3.3.1, R3.3.2, and R3.3.3 instead. For item 3.4, it does not allow more severe faults; for example, if instead of bolting a fault at the highest voltage bus, faulting all lines into the station (regardless of voltage level) with a three phase bolted fault would arguably be a more severe event. However, the current language would not support running a more severe fault as an acceptable analysis. Furthermore, the 'highest voltage level bus' is ambiguous in cases where a station may have multiple bus sections (such as 500 kV breaker-and-a-half stations), or a transformer terminated line (such as a 500/230 kV transformer at a 230 kV station). In these cases, this prescriptive requirement seems to result in unclear or less severe events. Lastly, R3.6.2 currently requires the use of 'Actual clearing times', but the basis for this is unclear – hopefully these physical attacks have not occurred at many stations, so the 'actual' has never been observed. 'Expected' would be a more preferred term. Similarly, R3.6.1 requires use of Delayed (remote) clearing time, but if a scheme drops its zone 2 delay if communication is lost, here as well 'Expected' clearing time may be a better word choice.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	

Document Name	
Comment	
Louisville Gas & Electric and Kentucky Utilities support EEI's comments.	
Likes 0	
Dislikes 0	
Response	

5. Do you agree with the modifications made in CIP-014-4 with new Requirement R4 to address the issues identified in the SAR?

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
Unable to locate in the SAR where this is requested.	
Likes 0	
Dislikes 0	
Response	
Matt Carden - Southern Company - Southern Company Services, Inc. - 1	
Answer	No
Document Name	
Comment	
Southern Company agrees with the need to coordinate responsibilities. However, we seek clarification regarding the requirement to document every 36 months responsibilities for stations that have already previously been coordinated and documented in previous assessments. Additionally, Southern Company wants to confirm the SDT intends to only require this coordination for jointly owned stations – not also stations with one owner that may have jointly owned equipment.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
The R4 requirement goes beyond the SAR requiring coordination of responsibilities of jointly owned facilities every 36 calendar months. This is well beyond what the SAR states, and R4 should focus on written agreements determining responsibilities. Those agreements could sunset or be indefinite. Small entities, like those in the Pacific Northwest, commonly have interconnections with Bonneville Power, or other large agencies. They requirement to coordinate every 36 months will be burdensome, add compliance risk, and not enhance the process.	

Likes 0	
Dislikes 0	
Response	
Rebika Yitna - Rebika Yitna On Behalf of: Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	No
Document Name	
Comment	
Why is there a need to coordinate responsibilities every 36 months for stations that have already previously been coordinated and documented? Also, clarification is requested for 'jointly owned stations': Does the SDT intend to only require this coordination for jointly owned stations and not also for stations with one owner that may have jointly owned equipment?	
Likes 0	
Dislikes 0	
Response	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO, Group Name Manitoba Hydro Group	
Answer	No
Document Name	
Comment	
MH is suggesting including adjacent transmission owners with Transmission stations in close proximity (identified under R2) in addition to jointly owned Transmission stations to coordinate with each other when performing a risk assessment.	
Likes 0	
Dislikes 0	
Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	No
Document Name	
Comment	

Comment 24: R4 is worded that each Transmission Owner must coordinate with others on jointly owned facilities but does not indicate that this coordination can be performed concurrently. In addition, in R4 the inclusion of the at timing "…at least once every 36 months." Is easily confused with the timeframe for performing assessment in R5. Suggested rewording:

"At least once every 36 calendar months Transmission Owners with jointly owned Transmission station(s) and Transmission substation(s) shall jointly determine and identify each entity's individual and joint responsibilities for performing any required risk assessments.

Comment 25: R4 does not include details on how Transmission Owners shall coordinate with other sole-owners of proximal facilities identified in R2; it only discusses how to handle joint ownership. Suggest that R4 be expanded to make sure that Transmission Owners that own stations that are proximal are tested in a similar manner.

Likes 0	
Dislikes 0	

Response

Michele Shafer - New York State Electric & Gas (NYSEG) - 6

Answer	No
Document Name	

Comment

- R4 is worded that each Transmission Owner must coordinate with others on jointly owned facilities but does not indicate that this coordination can be performed concurrently. In addition, in R4 the inclusion of the at timing "…at least once every 36 months." Is easily confused with the timeframe for performing assessment in R5. Suggested rewording:
  "**At least once every 36 calendar months** Transmission Owner**s** with **jointly** owned Transmission station(s) and Transmission substation(s) shall jointly determine and identify each entity's individual and joint responsibilities for performing any required risk assessments.
- R4 does not include details on how Transmission Owners shall coordinate with other sole-owners of proximal facilities identified in R2; it only discusses how to handle joint ownership. Suggest that R4 be expanded to make sure that Transmission Owners that own stations that are proximal are tested in a similar manner.

Likes 0	
Dislikes 0	

Response

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB

Answer	No
Document Name	

Comment

TVA disagrees with the modifications made to R4. Additional clarity is needed regarding "coordination" and the compliance burden given the potential that one Transmission Owner may request coordination, but not receive a response from another Transmission Owner.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Insitute (EEI) for question #5.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

It appears to BPA that the SAR does not include content on a problem needing to be resolved when there is joint ownership of a substation. The SAR's purpose only states "Clarify how to account for adjacent Transmission stations or Transmission substations of differing ownership as well as for those Transmission stations or Transmission substations within line-of-sight to each other."

Likes 0	
Dislikes 0	

Response

Karen Demos - NextEra Energy - Florida Power and Light Co. - 3

Answer	No
Document Name	

Comment

NextEra/FPL supports EEI's comments

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5

Answer	No
Document Name	

Comment

NEE support's EEI comments: " EEI proposes the following revisions to Requirement R4:

Each Transmission Owner**s** with jointly owned Transmission station(s) and Transmission substation(s) shall coordinate to determine and identify each entity's individual and joint responsibilities for performing any required risk assessments at least once every 36 calendar months. "

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	No
Document Name	

Comment

Black Hills Corporation agrees with EEI comments and the proposed changes.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy supports EEI comments.

Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
For R4, the requirement should include join ownership proximity groups. *Each Transmission Owner with jointly owned Transmission station(s), Transmission substation(s)* ***and proximity groups*** *shall coordinate to determine and identify each entity's individual and joint responsibilities for performing any required risk assessments at least once every* 36 calendar months.	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Louisville Gas & Electric and Kentucky Utilities support EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP supports the MRO NSRF with Tacoma Power's comments.	

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

The standard or guidance should explain how disagreements between entities should be handled.

It is not clear if R4 is intended to incorporate the stations in close proximity identified in R2.

Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	

Thank you for the chance to comment, SERC appreciates the complexity of the SDT's task of modifying multiple parts of such a high profile and high-priority standard.

Item #4.A: We would suggest the joint ownership language be made inclusive of multiple owners of Transmission Elements within a Transmission Station/Substation (vs ownership of the Station/Substation itself) since mixed ownership of the land, protection system components, and BES Facilities within and extending outward from the substation may vary significantly. One suggestion would be to state : "Each Transmission Owner with Transmission stations and Transmission Substations where a portion of the of the locations or its contents are jointly owned with another entity, shall….". This would allow flexibility under different ownership situations to be addressed in the manner desired by the owners and increase clarity.

Item #4.B SAR Scope Item #5 states "Clarify how to account for adjacent Transmission stations or Transmission substations of differing ownership…" It appears that conflict may arise if two separate TOs come to differing conclusions about the methodology parameters and criteria in R2, R3, and ultimately R5. This tracks back to gaining the full clarity mentioned in SAR Detailed Description #5: *"Provide clear expectations regarding the inclusion of physically adjacent elements for the purpose of evaluating the impact from a physical attack."* It is unclear on how the requirements as written will ensure consistency in inclusion such that the two (or more) differing owners do not come to different conclusions about the composition of proximity groups, the criteria for the risk assessment methodology, or the conclusions of the methodology per substation. Would it be clearer to state that absent some other factor, the most limiting of two competing conclusions would be used, similar to the language in TOP-001-6 R18?

Item #4.C: We would suggest that the phrase "and document" follow the verb "coordinate" to provide clarity on compliance evidence expectations. Evidentiary capture and demonstration of coordination occurring at a certain date has been difficult and problematic in other past standards, such as CIP-012-1 R1.3 ("…identification of…") and CIP-013-2 R1.1 ("…assess…") – adding "document" or a similar verb could address this.

Likes 0	
Dislikes 0	

Response

Jeffrey Streifling - NB Power Corporation - 1

Answer	No
Document Name	

Comment

Is the 36-month periodicity regarding the coordination, the risk assessment, or both? We suggest adding that only changes in responsibilities of Joint substation or stations should be documented once every 36 months or attestation that no changes occurred in responsibilities during the 36-month period. At scale, these substation and stations can be an administrative burden due to the number of agreements an entity may have, and an overarching document may be a better solution for management of these agreements. We are unsure of the intended goal or end value of the requirement and would like clarification.
Does the outcome of the risk assessment need to be agreed to by both parties of a Joint substation or station? Additional clarification on what is expected for the outcome of the coordinated risk assessment should be clarified.

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	No
Document Name	

Comment

Is the 36-month periodicity regarding the coordination, the risk assessment, or both? We suggest adding that only changes in responsibilities of Joint substation or stations should be documented once every 36 months or attestation that no changes occurred in responsibilities during the 36-month period. At scale, these substation and stations can be an administrative burden due to the number of agreements an entity may have, and an overarching document may be a better solution for management of these agreements. We are unsure of the intended goal or end value of the requirement and would like clarification.

Does the outcome of the risk assessment need to be agreed to by both parties of a Joint substation or station? Additional clarification on what is expected for the outcome of the coordinated risk assessment should be clarified.

Likes 0	
Dislikes 0	

Response	
Fon Hiew - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	No
Document Name	
Comment	
Is the 36-month periodicity regarding the coordination, the risk assessment, or both? We suggest adding that only changes in responsibilities of Joint substation or stations should be documented once every 36 months or attestation that no changes occurred in responsibilities during the 36-month period. At scale, these substation and stations can be an administrative burden due to the number of agreements an entity may have, and an overarching document may be a better solution for management of these agreements. We are unsure of the intended goal or end value of the requirement and would like clarification. Does the outcome of the risk assessment need to be agreed to by both parties of a Joint substation or station? Additional clarification on what is expected for the outcome of the coordinated risk assessment should be clarified.	
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	
MPC strongly disagrees with the use of a 36 month timeframe for utilities who have not previously identified substations as critical for the same reasons specified in our comments for question 6.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	

Minnesota Power supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren supports EEI's comments on this project.	
Likes 0	
Dislikes 0	
Response	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI proposes the following revisions to Requirement R4: Transmission Owner**s** with jointly owned Transmission station(s) and Transmission substation(s) shall coordinate to determine and identify each entity's individual and joint responsibilities for performing any required risk assessments.	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	

Jointly coordinating responsibilities related to an assessment is not problematic. However, this standard ties the risk assessment to analysis that the TO is not equipped to perform. Therefore, coordination is not possible until this problematic construct is addressed.	
Likes 0	
Dislikes 0	
Response	
James Baldwin - James Baldwin On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - James Baldwin	
Answer	No
Document Name	
Comment	
The standard or guidance should explain how disagreements between entities should be handled. It is not clear If R4 is intended to incorporate the stations in close proximity identified in R2.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Eclectic Institute	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	

Is the 36-month periodicity regarding the coordination, the risk assessment, or both? We suggest adding that only changes in responsibilities of Joint substation or stations should be documented once every 36 months or attestation that no changes occurred in responsibilities during the 36-month period. At scale, these substation and stations can be an administrative burden due to the number of agreements an entity may have, and an overarching document may be a better solution for management of these agreements. We are unsure of the intended goal or end value of the requirement and would like clarification.

Does the outcome of the risk assessment need to be agreed to by both parties of a Joint substation or station? Additional clarification on what is expected for the outcome of the coordinated risk assessment should be clarified.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

NV Energy supports the EEI response to this question.

Likes 0	
Dislikes 0	

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

See EEI comments

Likes 0	
Dislikes 0	

Response

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott

Answer	No

Document Name	
Comment	
ITC supports the EEI response	
Likes 0	
Dislikes 0	
Response	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
Answer	No
Document Name	
Comment	
PNM and TNMP support EEI comments regarding R4, noted again here *"EEI proposes the following revisions to Requirement R4:* *Transmission Owner**s** with jointly owned Transmission station(s) and Transmission substation(s) shall coordinate to determine and identify each entity's individual and joint responsibilities for performing any required risk assessments."*	
Likes 0	
Dislikes 0	
Response	
Jason Snodgrass - Jason Snodgrass On Behalf of: Katrina Lyons, Georgia System Operations Corporation, 3, 4; - Jason Snodgrass	
Answer	No
Document Name	
Comment	
GSOC supports comments provided by Georgia Transmission	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	

Answer	Yes
Document Name	
Comment	
FirstEnergy has no objection.	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
While WAPA agrees it is positive to have coordination with jointly owned entities, consider situations where the different methodologies result in a different answers, especially when taking into account different definitions of physical proximity.	
Likes 0	
Dislikes 0	
Response	
Michael Dillard - Austin Energy - 5, Group Name Austin Energy	
Answer	Yes
Document Name	
Comment	
Austin Energy supports MRO's comments. Attached in Question 1.	
Likes 0	
Dislikes 0	
Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	Yes
Document Name	

Comment	
We support the modifications made in R4.	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
As it is currently written the ordering with R4 coming later can cause some confusion and re-work. Consider combining / incorporating the intent of this Requirement into earlier Requirements, specifically R1 and R2, or reference R1 and R2 as part of R4.	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Request clarification on the determination and identification of each entity's individual and joint responsibilities for performing any required risk assessment. Does the determination need to be approved by both parties of the joint substation or station?	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	

Requirement R4 uses "jointly owned" which stalled Project 2021-08 is seeking to help define. Registered entities should be focused on the reliability aspects of both Projects and can easily limit compliance concerns by taking a practical approach to what is being requested to mitigate risk. Project 2021-08 suggested "For a BES Facility where no entity owns the Facility in its entirety, all applicable entities that own the Facility shall coordinate...". A similar approach should be used here by stating "A Transmission station or Transmission substation where no single entity owns all equipment within the Transmission station or Transmission substation shall coordinate and document…" (with "and document" added to ensure that efforts are reflected appropriately. Industry should understand the risk (here related to physical security and reliability) associated with Transmission station(s) and Transmission substation(s) with multiple owners needs to be addressed.

Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelley Sargent - Puget Sound Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lucinda Bradshaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tyler Schwendiman - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Leshel Hutchings - AEP - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

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

Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michael Jang - Seattle City Light - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Chris Shultz - Seattle City Light - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Zenon O'young-Chu - Seattle City Light - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

6. Do you agree with the modifications made in CIP-014-4 with adding Requirement R5 to address the issues identified in the SAR?

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
The current draft, R5 requires a risk assessment without explicitly stating what the risk assessment is supposed to achieve. ACES suggests clarifying language to have a clear objective outcome based on the assessment.	
Likes 0	
Dislikes 0	
Response	
Jason Snodgrass - Jason Snodgrass On Behalf of: Katrina Lyons, Georgia System Operations Corporation, 3, 4; - Jason Snodgrass	
Answer	No
Document Name	
Comment	
GSOC supports comments provided by Georgia Transmission	
Likes 0	
Dislikes 0	
Response	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
Answer	No
Document Name	
Comment	
PNM and TNMP support EEI comments regarding R4, noted again here *"EEI proposes the following revision to Requirement R5 because R1 is the only requirement that speaks directly to applicability:* *Each Transmission Owner shall conduct a risk assessment, using the methodology established in Requirement R3, on each Transmission station(s) and Transmission substation(s) identified as applicable in accordance with Requirements R1, R2, and R4 at least once every 36 calendar months.* ***Jointly owned Transmission station(s) and Transmission substation(s) identified as applicable in Requirement R1 shall be evaluated as coordinated in Requirement R4."***	

Likes 0	
Dislikes 0	

Response

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott

Answer	No
Document Name	

Comment

ITC supports the EEI response

Likes 0	
Dislikes 0	

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

See EEI comments

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

NV Energy supports the EEI response to this question.

Likes 0	
Dislikes 0	

Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	

We suggest tightening the language of Part 5.2 dealing with proximity and ability of a TO ability to designate a Control Center with other TO or TOPs.

We suggest added language about information security between entities where a TO designate another entities Control Center in part 5.2.

A Requirement R5.3 should be added stating something similar to "Transmission Owners of stations within proximity of other Transmission Owners as determined in R2 should share the results of their analyses related to the stations within proximity with all the other Transmission Owners of the stations within proximity."

Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	

See comments submitted by the Edison Eclectic Institute

Likes 0	
Dislikes 0	
Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	No
Document Name	
Comment	

IID disagrees with the language in Requirement R5 due to its lack of clear objectives or defined outcomes for implementation. The Requirement does not explicitly state the intended outcomes of the risk assessment nor clarify its purpose. It should be revised to address these aspects.

Likes 0	
Dislikes 0	

Response

James Baldwin - James Baldwin On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - James Baldwin

Answer	No
Document Name	

Comment

Under the Requirement, as currently written, it is unclear if the intent of R5.1 is to enable Registered Entities to maintain critical stations from previous 36-month assessments or if once a station is deemed critical during this year's study the additional studies in R3 are no longer necessary. R5 does not seem to address the next steps required after a proximity station not owned by a Registered Entity is identified as critical.

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	No
Document Name	

Comment

R5 requires a risk assessment without explicitly stating what the risk assessment is supposed to achieve. This lack of clarity is the only reason that a third-party verification of the assessment is needed. GTC suggests R5 be revised to clearly state the objective of the assessment, including the types of attacks to be simulated and acceptable resulting system response. Additionally, the reference to R3 is problematic as the TO is not equipped to perform the analysis prescribed in that requirement. This reference should be to a study/evaluation received from the appropriate planning entity.

Likes 0	
Dislikes 0	

Response

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment	
EEI proposes the following revision to Requirement R5 because R1 is the only requirement that speaks directly to applicability: Each Transmission Owner shall conduct a risk assessment, using the methodology established in Requirement R3, on each Transmission station(s) and Transmission substation(s) identified as applicable in accordance with Requirement R1 at least once every 36 calendar months. **Jointly owned Transmission station(s) and Transmission substation(s) identified as applicable in Requirement R1 shall be evaluated as coordinated in Requirement R4.**	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren supports EEI's comments on this project.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO-NSRF and EEI's 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	

MPC disagrees with the use of a 36 month timeframe for utilities who have not previously identified any substations as critical as it is both outside the scope of the SAR and will lead to increased study costs with little or no benefit. During the 6/7/24 NERC webinar for the SAR, the SDT stated a goal of changing the risk assessment timeframe to 36 months was to align the risk assessment with the model build time frame of another standard. This goal is outside the scope of the SAR and otherwise irrelevant as the CIP-014 risk assessment does not require the use of models built for any other standard.

Considering the very slow pace of construction of new electrical infrastructure, it is highly unlikely that a modification to an existing non-critical station or substation that would result in the station or substation becoming critical would be planned, designed, and constructed within 36 months. It is equally unlikely that a newly constructed CIP-014 critical substation would be completed within this timeframe. As stations and substations planned to be in service within 24 months of the risk assessment are already required to be included under R1 of CIP-014-3, changing the risk assessment timeframe from 60 months to 36 months is very unlikely to identify stations or substations that would not be identified under CIP-014-3.

For utilities who have not identified previously identified substations as critical, moving the risk assessment timeframe to 36 months will result in increased costs due to more frequent risk assessments, with the more frequent assessments having no benefit as they have little to no chance of identifying stations or substations as CIP-014 critical that would not already have been under CIP-014-3.

Likes 0	
Dislikes 0	
Response	
Fon Hiew - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	No
Document Name	
Comment	

We suggest tightening the language of Part 5.2 dealing with proximity and ability of a TO ability to designate a Control Center with other TO or TOPs.

We suggest added language about information security between entities where a TO designate another entities Control Center in part 5.2.

A Requirement R5.3 should be added stating something similar to “Transmission Owners of stations within proximity of other Transmission Owners as determined in R2 should share the results of their analyses related to the stations within proximity with all the other Transmission Owners of the stations within proximity."

Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	No

Document Name	
Comment	

We suggest tightening the language of Part 5.2 dealing with proximity and ability of a TO ability to designate a Control Center with other TO or TOPs.

We suggest added language about information security between entities where a TO designate another entities Control Center in part 5.2.

A Requirement R5.3 should be added stating something similar to “Transmission Owners of stations within proximity of other Transmission Owners as determined in R2 should share the results of their analyses related to the stations within proximity with all the other Transmission Owners of the stations within proximity."

Likes 0	
Dislikes 0	
Response	

Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	

We suggest tightening the language of Part 5.2 dealing with proximity and ability of a TO ability to designate a Control Center with other TO or TOPs.
We suggest added language about information security between entities where a TO designate another entities Control Center in part 5.2.
A Requirement R5.3 should be added stating something similar to “Transmission Owners of stations within proximity of other Transmission Owners as determined in R2 should share the results of their analyses related to the stations within proximity with all the other Transmission Owners of the stations within proximity."

Likes 0	
Dislikes 0	
Response	

Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	

Item #5.A: In R5, the requirement language mentions “…on each transmission station(s) and Transmission substations…”. The word “each” is unclear if this is meant to also refer to substation proximity groups from R2/R3.5 as well as individual substations. Clarity in this linking language could provide clarity.

Item #5.B: In R5.1, the term "critical" is used for the first time. Is the implication that applicable Transmission Stations/Substations (or entire proximity groups) that 'fail' the R5 risk assessment are then formally called "critical"? Language indicating that in R5 (root) would be helpful, as R5.1 reads more as an exclusion. The language would likely need to be made consistent in other parts of the standard, such as R6.3, R8, R9, etc.

Item #5.C: In R5.1, in one case the requirement states, "identified as critical" and another states "classified as critical". Are these different states, or could the verbs be standardized?

Item #5.D: In R5.2, the phrase "primary control center" does not utilize the NERC defined term 'Control Center'. The Control Center term from the 706SDT had not reached its Effective Date at the time the original CIP-014-1 reached its compliance date, however moving to the standardized term now would reduce confusion and divergence between CIP-014 and the remainder of the CIP standards, especially as future standards projects occur. We do agree with retaining the qualifier of "…that operationally controls…" to delineate between primary and cold backup sites.

Item #5.E: In 5.2, the requirement does not acknowledge the situation where multiple control centers owned by different Responsible Entities (such as those with joint ownership as described in R4) may control some, but not all, of the Transmission Elements in a Transmission station/substation. There also exists the reality where some TO/TOPs may operate multiple 'hot-hot' Control Centers that are both constantly staffed and are able to immediately operationally control Transmission Elements. Suggest the term read "…primary control center(s)…" or "…primary Control Center(s)…" to affirm that all control centers with operational control need to be identified and allow flexibility for different types of Control Center configurations and joint ownership and operation of Elements.

Item #5.F: In M5 (the measures for R5) suggest a clarification the that "..dated written or electronic documentation of the risk assessment satisfying Requirement R5 for **each** Transmission station and Transmission substation…" to clarify the level of detail needed, instead of an high-level executive summary of its performance.

Likes 0	
Dislikes 0	

Response

Teresa Krabe - Lower Colorado River Authority - 5

Answer	No
Document Name	

Comment

Under the Requirement, as currently written, it is unclear if the intent of R5.1 is to enable Registered Entities to maintain critical stations from previous 36-month assessments or if once a station is deemed critical during this year's study the additional studies in R3 are no longer necessary. R5 does not seem to address the next steps required after a proximity station not owned by a Registered Entity is identified as critical.

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez

Answer	No

Document Name	
Comment	

SRP supports the MRO NSRF with Tacoma Power's comments.

Likes 0	
Dislikes 0	
Response	

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	No
Document Name	
Comment	

Louisville Gas & Electric and Kentucky Utilities support EEI's comments.

Likes 0	
Dislikes 0	
Response	

John Pearson - ISO New England, Inc. - 2

Answer	No
Document Name	
Comment	

Does R5.1 mean that once a station or substation becomes critical, then it is forever critical? This seems arbitrary since there is no requirement to retest critical stations. Over time and with system topology changes, stations may no longer be critical and provisions should be made to perform periodic reviews to determine if they remain CIP-014 critical.

Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment	
Dominion Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	No
Document Name	
Comment	
We recommend that the Drafting Team clarify applicability in R5. Are R3.2.2 and R5.1 redundant to each other?	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with EEI comments that the proposed modification to Requirement R5, have the references to R2 and R4 removed from R5, as only Requirement R1 sets the applicable station(s) or substation(s).	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No
Document Name	

Comment	
Requirement R5 does not specify what outcome the risk assessment is trying to achieve. The Standards Drafting Team should revise the language to ensure the risk assessment identifies which Transmission station(s) and Transmission substation(s) are “critical” and provide parameters for what “critical” means. As currently written, Requirement R5 has the Transmission Owner identify the primary control center that operationally controls each Transmission station or Transmission substation classified as critical, however, the identification of the “critical” Transmission station(s) or Transmission substation(s) is missing. We recommend that the Standards Drafting Team revise Requirement R5 to clarify that the outcome of the risk assessment is the identification of the “critical” Transmission station(s) or Transmission substation(s). To accomplish this, we propose the following language for Requirement R5: “Each Transmission Owner shall conduct a risk assessment, using the methodology established in Requirement R3, on each Transmission station(s) and Transmission substation(s) identified as applicable in accordance with Requirements R1, R2, and R4 at least once every 36 calendar months **to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection**”. No changes are necessary for sub-requirements R5.1 and R5.2.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State agrees with the MRO NSRF Submitted Comments	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
NEE support’s EEI comments: “EEI proposes the following revision to Requirement R5 because R1 is the only requirement that speaks directly to applicability:	

Each Transmission Owner shall conduct a risk assessment, using the methodology established in Requirement R3, on each Transmission station(s) and Transmission substation(s) identified as applicable in accordance with Requirements R1, R2, and R4 at least once every 36 calendar months. **Jointly owned Transmission station(s) and Transmission substation(s) identified as applicable in Requirement R1 shall be evaluated as coordinated in Requirement R4.** "	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC signed on to ACES comments below: The current draft, R5 requires a risk assessment without explicitly stating what the risk assessment is supposed to achieve. ACES suggests clarifying language to have a clear objective outcome based on the assessment.	
Likes 0	
Dislikes 0	
Response	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	No
Document Name	
Comment	
Modifying the study periodicity requirement from 60-months (CIP-014-3) to 36-months (CIP-014-4) increases consumption of resources for utilities that do not own any applicable stations that, if rendered damaged or inoperable as a result of a physical attack, result in instability, uncontrolled islanding, or Cascading. The updates to CIP-014-4 R1 requiring TOPs to establish and a maintain a list every 36-months can help address the issues identified in the SAR but requiring all TOPs to conduct an assessment every 36 months increases burden on utilities that have previously only been required to perform CIP-014 studies in alignment with the 60-month requirement. However, if R1 could include the new 36-month list maintenance periodicity while R5 maintains the existing CIP-014-3 60 calendar month periodicity for utilities that demonstrate through their completed CIP-014 risk assessments that they do not own these impactful facilities, then the proposed updates to R1 and R5 support NERC goals to address issues identified in the SAR without causing additional burden. Additionally, as noted in prior comments, R5's assessment does not allow for/contemplate how utilities may change / remediate performance deficiencies to not cause cascading, instability, or uncontrolled separation. This is a more positive outcome for the system than a tall fence and a big gate, to which an attacker may simply move to the 1st transmission structures outside the station and cause the same level of damage, with the added station protections under CIP-014 for naught.	

Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC agrees with the 36-calendar month time frame, but does not agree with R3 details as written, due to the reasons mentioned in Question 4	
Likes 0	
Dislikes 0	
Response	
Michael Dillard - Austin Energy - 5, Group Name Austin Energy	
Answer	No
Document Name	
Comment	
Austin Energy supports MRO's comments. Attached in Question 1.	
Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas and Electric d/b/a CenterPoint Energy Indiana South (SIGE) agrees with the 36-calendar month time frame, but does not agree with R3 details as written, due to the reasons mentioned in Question 4.	
Likes 0	

Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
WAPA concurs with the comments provided by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Karen Demos - NextEra Energy - Florida Power and Light Co. - 3	
Answer	No
Document Name	
Comment	
NextEra/FPL supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA agrees with conducting risk assessments every 36 months for Transmission station(s) or Transmission substation(s) identified as applicable. BPA does not agree with requiring subsequent risk assessment(s) if they continue to be classified as critical.	
Likes 0	
Dislikes 0	
Response	

Leshel Hutchings - AEP - 3	
Answer	No
Document Name	
Comment	
R5 Section 5.1 5.1 is duplicative with 3.2.2 – suggest removing 5.1 or at least one of them.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Insitute (EEI) and MRO NSRF for question #7.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
As drafted, R5 requires a risk assessment without explicitly stating what the risk assessment is supposed to achieve. The MRO NSRF recommends adding language to clarify the objective or outcome of the risk assessment, “to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged though a realistic physical attack scenario could result in instability, uncontrolled separation, or Cascading within an Interconnection”. Additionally, the SDT should clarify within R5.1 that an entity can deem one of its substations as critical and treat it as such without having to perform a risk assessment. This can either be a substation that had a previous risk assessment performed and does not require a subsequent (as 5.1 is currently	

drafted), or a substation that the entity volunteers to treat a critical without any risk assessment. It sounds like the SDT had this intent in the draft, but the wording does not make this clear.	
Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	No
Document Name	
Comment	
• R5 states facilities "…identified as applicable in accordance with Requirements R1, R2 and R4…" however, R4 does include information on applicability of facilities. Suggest that the final sentence of R5 be reworded: "Each Transmission Owner shall conduct a risk assessment, using the methodology established in Requirement R3, on each Transmission station(s) and Transmission substation(s) identified as applicable in accordance with Requirements R1, R2 **and the individual and joint responsibilities identified in R4**, at least once every 36 calendar months."	
Likes 0	
Dislikes 0	
Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	No
Document Name	
Comment	
Comment 26: R5 states facilities "…identified as applicable in accordance with Requirements R1, R2 and R4…" however, R4 does include information on applicability of facilities. Suggest that the final sentence of R5 be reworded: *"Each Transmission Owner shall conduct a risk assessment, using the methodology established in Requirement R3, on each Transmission station(s) and Transmission substation(s) identified as applicable in accordance with Requirements R1, R2 and the individual and joint responsibilities identified in R4, at least once every 36 calendar months."*	
Likes 0	
Dislikes 0	
Response	
Lucinda Bradshaw - Oncor Electric Delivery - 1 - Texas RE	

Answer	No
Document Name	

Comment

See Oncor's Comments in response to Question 2 above.

Likes 0	
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Tacoma Power supports the MRO NSRF comments, as follows.

As drafted, R5 requires a risk assessment without explicitly stating what the risk assessment is supposed to achieve. The MRO NSRF recommends adding language to clarify the objective or outcome of the risk assessment, "to identify the Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged though a realistic physical attack scenario could result in instability, uncontrolled separation, or Cascading within an Interconnection".

Additionally, the SDT should clarify within R5.1 that an entity can deem one of its substations as critical and treat it as such without having to perform a risk assessment. This can either be a substation that had a previous risk assessment performed and does not require a subsequent (as 5.1 is currently drafted), or a substation that the entity volunteers to treat a critical without any risk assessment. It sounds like the SDT had this intent in the draft, but the wording does not make this clear.

Likes 0	
Dislikes 0	

Response

Kevin Conway - Western Power Pool - 4

Answer	No
Document Name	

Comment

The first concern is in R 5.2 where the Transmission Owner is responsible for the primary [C]control [C]enter identification. TOs do not operate control centers and have no authority to designate what their TOP choses to do. In smaller agencies there may be multiple primary Control Centers due the geographic operation of the entity. In the case of this requirement the use of "control center" in its non-capitalized form causes confusion which has been a problem for several Standard Drafting Teams. The Drafting Team should consider that every TO must provide a list of its critical facilities to the TOP. The TOP must declare the associated “Control Centers” critical if there are any identified critical facilities that it controls.

R 5 is appropriately requiring a review of the facilities every 36 months. R5.1 should be removed since it allows an entity to forego a reassessment of the facilities’ threats and vulnerabilities. These will change over time, and although a critical facility may remain classified as critical, the Risk Assessment may change and require additional, or different mitigation measures.

Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
Recommend removal of R5.1 entirely. Does not provide for de-classification of a Transmission Substation from critical to non-critical. Does not prevent a station from being studied once and never re-evaluated in subsequent risk assessments.	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	

There is no context provided for determining what is "critical". Should the context be "Those Transmission station(s) and Transmission substation(s) whose loss results in or that cause instability, uncontrolled separation or Cascading are considered critical"? Need to address use of "months" versus "calendar months". Is R2 already subsumed by R1's reference to using Attachment 1 which contains bullet 2.1? If considered added for clarity (which is appropriate) then the DT should consider similar language in R3. Capitalize "control center" as it is a defined term. Understood that the lower case term originated from FERC but FERC also lower cases functional entities. NERC Standards should be consistent. May also need to pluralize Control Center to avoid confusion.

Likes 0	
Dislikes 0	

Response

Robert Jones - Seattle City Light - 4

Answer	Yes
Document Name	

Comment

Language in 5.2 could use some work on clarity.

Likes 0	
Dislikes 0	

Response

Chris Shultz - Seattle City Light - 5

Answer	Yes
Document Name	

Comment

Language in 5.2 could use some work on clarity.

Likes 0	
Dislikes 0	

Response

Mark Flanary - Midwest Reliability Organization - 10

Answer	Yes
Document Name	

Comment	
While it's implied by the order of the requirements, it could be clarified that R5 would be completed after R1-R4 to ensure the risk assessment is properly informed. Performing the Requirements out of order can create a situation where the risk assessment is not using information that accurately represents the current environment. Consider a timing component to the requirement, such as "Following completion of R1, R2, and R4, within # calendar months complete a risk assessment..."	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no objection.	
Likes 0	
Dislikes 0	
Response	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO, Group Name Manitoba Hydro Group	
Answer	Yes
Document Name	
Comment	
It is recommended that R5 also provides the flexibility to remove non-critical stations from subsequent risk assessments provided that TOs provide a technical justification.	
Likes 0	
Dislikes 0	
Response	
Rebika Yitna - Rebika Yitna On Behalf of: Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	Yes
Document Name	

Comment	
Only if the language in R3 is updated to be less prescriptive.	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Zenon O'young-Chu - Seattle City Light - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jang - Seattle City Light - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1,3,5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tyler Schwendiman - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelley Sargent - Puget Sound Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matt Carden - Southern Company - Southern Company Services, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	
Document Name	
Comment	
IID disagrees with the language in Requirement R5 due to its lack of clear objectives or defined outcomes for implementation. The Requirement does not explicitly state the intended outcomes of the risk assessment nor clarify its purpose. It should be revised to address these aspects.	
Likes 0	
Dislikes 0	
Response	

7. Do you agree with the Implementation Plan for CIP-014-4?	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
Clearly define completion of initial CIP-014-4 Risk Assessment and transition from CIP-014-3. Initial CIP-014-4 Risk Assessment should be completed within 30 months of the previous CIP-014-3 Risk Assessment.	
Likes 0	
Dislikes 0	
Response	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO, Group Name Manitoba Hydro Group	
Answer	No
Document Name	
Comment	
Manitoba Hydro agrees with the content and timelines in the implementation plan however as written the standard would be difficult to implement effectivly in that timeline (please see previous comments).	
Likes 0	
Dislikes 0	
Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	No
Document Name	
Comment	
Comment 27: It is conceivable that an entity may have finished a CIP-014-3 study just prior to CIP-014-4 becoming effective. If the SDT believes that a CIP-014-4 study meets the requirements of CIP-014-4 it should be documented in the Implementation Plan to assist entities in that situation.	
Likes 0	
Dislikes 0	

Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	No
Document Name	
Comment	
• It is conceivable that an entity may have finished a CIP-014-3 study just prior to CIP-014-4 becoming effective. If the SDT believes that a *CIP-014-4* study meets the requirements of CIP-014-4 it should be documented in the Implementation Plan to assist entities in that situation.	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	No
Document Name	
Comment	
TVA requests the implementation plan be moved from 24 to 36 months.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Insitute (EEI) for question #7.	
Likes 0	
Dislikes 0	
Response	

Leshel Hutchings - AEP - 3	
Answer	No
Document Name	
Comment	

The implementation plan is 24 months, and the compliance timeline is 36 months. The implementation plan should be 36 months, no shorter.

The proposed implementation plan is 24 months. This means some Transmission Owners may have insufficient time, less than 36 months, to complete their next assessment based on the new standard. Example: a TO with an existing compliance deadline at the end of this year may fall under the shortened timeline. For large TOs, the existing applicability scoring, case prep, steady state and stability analysis, and third-party review can take as long as 1 year to perform per region. AEP has three regions (PJM, SPP, and ERCOT), which each take this amount of time. With the proposed proximity/applicability changes, scenario changes, and this implementation period would be insufficient time to adopt and reperform the assessment. In addition, given the new proximity criteria some small TOs may not have had any applicable stations previously and will have to create a new methodology and perform the assessment from scratch within that short 24-month period.

Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

The current cycle for CIP-014-3 R1 is 30 months. BPA believes requiring a fixed mandatory enforcement date may not align with entities' assessment schedules. BPA seeks clarity regarding how the SDT believes entities will demonstrate compliance with CIP-014-3 R1, then a new mid-cycle R1 assessment for CIP-014-4 R1.

Likes 0	
Dislikes 0	
Response	

Karen Demos - NextEra Energy - Florida Power and Light Co. - 3	
Answer	No
Document Name	
Comment	

NextEra/FPL supports EEI's comments

Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with EEI comments on the clarification of the Implementation Plan for CIP-014-4.	
Likes 0	
Dislikes 0	
Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy support EEI comments on the implementation plan.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP supports the MRO NSRF with Tacoma Power’s comments.	
Likes 0	
Dislikes 0	

Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
LCRA would like the Implementation Plan to include language addressing early adoption.	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
Thank you for the chance to comment, SERC appreciates the complexity of the SDT's task of modifying multiple parts of such a high-profile and high-priority standard. · Item #Implement.A: Given the long timelines and consideration of substations or Transmission elements to be constructed in the future, the Implementation plan should explicitly provide more detailed examples to cover scenarios such as the identification of a station being put in service within the next 36 months, responsibilities for newly registered entities, what constitutes an "unplanned change"', etc. These are common questions received given the longer time horizons of the new R1-R5, especially since CIP-014 is not dependent on CIP-002-5.1a R1/R2 for initiation/identification/classification. By providing concrete written examples in the Implementation Plan now (instead of in future Implementation Guidance), clarity on these situations would also address the SAR's Detailed Description #2, *"…Revisions to the risk assessment should be made to only include transmission and generation projects that are appropriate to the periodicity of the entity's risk assessments. Determinations of appropriateness should be clarified to align study periods, frequency of studies, and the power flow models used."*	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Requirement Part 1.2 states that a review of the list of applicable Transmission station(s) and Transmission substation(s) shall be done every 36 months. Absent a specified initial performance date in the implementation plan, the Transmission Owner would have until 36 months after the effective to establish its first list of Transmission station(s) and Transmission substation(s). Texas RE recommends the implementation plan specify the list shall be established by the effective date of the standard to avoid delaying compliance obligations an additional 36 months.

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	

Comment

Minnesota Power supports EEI's comments.

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	No
Document Name	

Comment

The construct of requiring the TO to perform analysis under R3 needs to be removed from this standard and addressed in TPL space. The 24 month implementation included in this plan is not sufficient to accomplish this.

Likes 0	
Dislikes 0	

Response

James Baldwin - James Baldwin On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - James Baldwin

Answer	No
Document Name	

Comment

LCRA would like the Implementation Plan to include language addressing early adoption.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Eclectic Institute	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy supports the EEI response to this question. Additionally, the increased complexity of the standard will require entities to create new definitions and measurements for the new standard language in addition to implementing the practical ramifications of new study measurements. Current language also is suggestive of prior physical security assessments conducted with existing R4 and R5 standards may also need to be considered as data points in the CIP-014-4 R2 assessment requiring an amalgamation of transmission planning and physical security data to determine risk to the technical functionality and stability of substation equipment. The time necessary to implement is difficult to forecast at this juncture due to the potential for significant change.	
Likes 0	
Dislikes 0	
Response	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
Answer	No
Document Name	

Comment	
PNM and TNMP propose 36 calendar months from date of last assessment performed under CIP-014-3 R1 or 24 calendar months of the effective date whichever is longer.	
Likes 0	
Dislikes 0	
Response	
Jason Snodgrass - Jason Snodgrass On Behalf of: Katrina Lyons, Georgia System Operations Corporation, 3, 4; - Jason Snodgrass	
Answer	No
Document Name	
Comment	
GSOC supports comments provided by Georgia Transmission	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no objection to the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Michael Dillard - Austin Energy - 5, Group Name Austin Energy	
Answer	Yes
Document Name	
Comment	

Austin Energy supports MRO's comments. Attached in Question 1.	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
The current Standard, CIP-014-4, Requirement 1, requires the risk performance to occur either every 30 or 60 calendar months. When the new Standard becomes effective Entities will be at different points in their cycles which could cause conflict or confusion. Consider providing guidance regarding how to handle situations where Entities are performing studies sufficiently out of cycle that a gap would be created, especially those Entities that are currently only required to perform the study every 60 months, or possibly providing an early adoption option.	
Likes 0	
Dislikes 0	
Response	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports a 24-calendar month implementation period but asks the drafting team to consider adding clarifying language to the implementation plan related to the implementation of periodic requirements. EEI interprets the draft Implementation Plan to mean that entities who must perform a risk assessment according to the requirements and timeframes in the currently enforceable CIP-014-3 after CIP-014-4 is approved but before the end of the 24-calendar month implementation period concludes, can perform the risk assessment under either version of the Standard. Subsequent risk assessments conducted after the end of the 24-calendar month implementation period would have to be performed in compliance with CIP-014-4. This is the preferred interpretation of the draft Implementation Plan, please add clarifying language to support this interpretation.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	

Answer	Yes
Document Name	
Comment	
Exelon support the EEI comment to clarify the latitude for entities to perform assessments based on CIP-014-3 during the implementation period.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Drawing a timeline for Implementation dates and ensuring future applicability is stated (Performance expectations) would benefit all implementation plans. The DT needs to consider "new" ownership (both new TOs or TOs subsumed by other existing TOs).	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matt Carden - Southern Company - Southern Company Services, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennie Wike - Jennie Wike On Behalf of: John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebika Yitna - Rebika Yitna On Behalf of: Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kelley Sargent - Puget Sound Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lucinda Bradshaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tyler Schwendiman - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fon Hiew - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
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	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 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 NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mike Magruder - Avista - Avista Corporation - 1,3,5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jang - Seattle City Light - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Shultz - Seattle City Light - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Daren Brubaker - Seattle City Light - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Zenon O'young-Chu - Seattle City Light - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	
Document Name	
Comment	
NEE support's EEI comments: "EEI supports a 24-calendar month implementation period but asks the drafting team to consider adding clarifying language to the implementation plan related to the implementation of periodic requirements. EEI interprets the draft Implementation Plan to mean that entities who must perform a risk assessment according to the requirements and timeframes in the currently enforceable CIP-014-3 after CIP-014-4 is approved but before the end of the 24-calendar month implementation period concludes, can perform the risk assessment under either version of the Standard. Subsequent risk assessments conducted after the end of the 24-calendar month implementation period would have to be performed in compliance with CIP-014-4. This is the preferred interpretation of the draft Implementation Plan, please add clarifying language to support this interpretation. "	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	
Document Name	

Comment

Louisville Gas & Electric and Kentucky Utilities support EEI's comments.

Likes 0

Dislikes 0

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer

Document Name

Comment

Ameren supports EEI's comments on this project.

Likes 0

Dislikes 0

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6

Answer

Document Name

Comment

See EEI comments

Likes 0

Dislikes 0

Response

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott

Answer

Document Name

Comment

ITC supports the EEI response

Likes 0	
Dislikes 0	

Response

8. Do you agree that CIP-014-4 is cost effective to address the reliability issue of physical security? If no, why not?

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
Based on this draft and the recommended changes, it is not possible to understand the cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Jason Snodgrass - Jason Snodgrass On Behalf of: Katrina Lyons, Georgia System Operations Corporation, 3, 4; - Jason Snodgrass	
Answer	No
Document Name	
Comment	
GSOC supports comments provided by Georgia Transmission	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	No
Document Name	
Comment	
Comments: The proposed draft of CIP-014 is too prescriptive. This includes but is not limited to the fault types and items to be monitored. The list of items proposed to be used to identify close proximity is too prescriptive and would require a site visit to each applicable station to confirm if any of the proposed attributes are present. Mileage between the stations should be added to R2.1 and it should be modified to only require one or more attributes. For R2, the phrase 'of irrespective of ownership' should be removed.	
Likes 0	
Dislikes 0	

Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
Costs are difficult to forecast at this juncture.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Eclectic Institute	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
The current proposed revision to CIP-014 is not deemed cost-effective. Managing the protection of neighboring facilities owned by different entities can be both costly and repetitive for any organization.	
Likes 0	
Dislikes 0	
Response	

Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	No
Document Name	
Comment	
The current proposed revision to CIP-014 is not deemed cost-effective. Managing the protection of neighboring facilities owned by different entities can be both costly and repetitive for any organization.	
Likes 0	
Dislikes 0	
Response	

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	
The overall changes to this standard cannot easily be evaluated from a cost-effectiveness perspective. However, there are some areas of added cost that could be removed from the standard. For example, regarding requirement R6, if the assessment is conducted by a TP or PC using a more prescriptive CIP-014 (R3.1), then it should no longer be necessary to have an unaffiliated third-party verifier. This requirement appears to cause an undue burden/expense on the responsible entity with little to no gain. There are no other studies or assessments conducted by the TP or PC that require this oversight or gives reason to question the judgment of the TP or PC. The responsible entity will either conduct the assessment according to the standard or face the repercussions of non-compliance.	
Likes 0	
Dislikes 0	
Response	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO-NSRF’s 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	
Requiring the CIP-014 risk assessment every 36 months for utilities who have not previously identified any stations or substations as critical will not be cost effective; see MPC's comments in response to question 6.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP supports the MRO NSRF with Tacoma Power's comments.	
Likes 0	
Dislikes 0	
Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	No
Document Name	
Comment	
As proposed, the continued ambiguity in CIP-014 is not a cost-effective approach to identifying and implementing physical security improvements. Simulating implausible study scenarios is a foundational challenge to maintaining cost effectiveness.	
Likes 0	

Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	No
Document Name	

Comment

This proposed version of CIP-014-4 is not cost effective as it would automatically designate any Transmission station(s) or Transmission substation(s) **in proximity** to a critical Transmission station(s) or Transmission substation(s) as critical, regardless of ownership, size, or ability to cause (by itself) instability, uncontrolled separation, or Cascading within an Interconnection. The changes proposed would commit small entities to implement expensive physical security plans that would not be required if they were not physically located in proximity to an existing critical Transmission station or Transmission substation.

Also, the risk assessments required by CIP-014 are not quick and easy to do. Requirement R5 requires the risk assessment be performed every 36 calendar months regardless if there is no change in applicable Transmission station(s) and Transmission substation(s). CIP-014-4 should give some consideration and leeway to allow entities with no changes in their list(s) of applicable assets to perform risk assessments every 60 months.

Likes 0	
Dislikes 0	

Response

Donna Wood - Tri-State G and T Association, Inc. - 1

Answer	No
Document Name	

Comment

Tri-State agrees with the MRO NSRF Submitted Comments

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	No
Document Name	

Comment	
AEPC signed on to ACES comments below: Based on this draft and the recommended changes, it is not possible to understand the cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Michael Dillard - Austin Energy - 5, Group Name Austin Energy	
Answer	No
Document Name	
Comment	
Austin Energy supports MRO's comments. Attached in Question 1.	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
WAPA concurs with the comments provided by the MRO NSRF. In addition, the physical proximity criteria could result in a significant increase in the groups of substations evaluated, adding cost and time burdens. There is no technical justification or documented physical threat that supports the significant cost of evaluating and protecting these low-risk stations.	
Likes 0	
Dislikes 0	
Response	
Karen Demos - NextEra Energy - Florida Power and Light Co. - 3	
Answer	No
Document Name	

Comment	
NextEra/FPL supports EEI's comments	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA does not believe the standard, as is, is cost effective in addressing the reliability of physical security. The spectrum of sites is too broad. BPA believes there is high potential for sites to be identified on a CIP-014-4 list that would have little to no effect on the BES if they were disconnected from the grid. The standard, as is, allows sites with RAS capability to be listed as CIP-014, which mitigates an enormous amount of risk, some might argue all risk. The number of sites that could potentially be categorized as CIP-14 takes resources away from other sites along critical pathways, and sites that directly link to critical infrastructure. Additionally, day to day operations of upstream and downstream sites affect whether singular or multiple pieces of equipment in a site are critical.	
Likes 0	
Dislikes 0	
Response	
Leshel Hutchings - AEP - 3	
Answer	No
Document Name	
Comment	
While this SAR focused on the R1 risk assessment, the most effective protection against all possible threat vectors is to plan redundancy into the Transmission system to remove single points of failure. Protecting individual stations against specific threats will always be less effective than Transmission build out. The standard should be revised to consider Transmission Planning mitigations rather than defaulting to adding physical security.	
Likes 0	
Dislikes 0	
Response	

Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the MRO NSRF for question #8.	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	No
Document Name	
Comment	
CIP-014-4 does not prescribe cost effective remedies that functionally increase physical security and/or promote system reliability. Forcing entities to study one specific event in the standard, without consideration for precedent and probability, means that funds are either used to construct ineffective physical barriers or to implement costly transmission system upgrades for a system condition that will never occur. Entities should define and study events which have some probability of occurring on their system. These validated events can then serve as the basis to determine whether a physical barrier or transmission system upgrades are better suited for the safety and reliability of that entity's system.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
It is too early in the process to effectively assess the cost considerations. However, these changes have the potential to add cost burden to smaller entities who fall under Attachment 1, Criterion 2.1, or those entities who previously completed studies every 60 months and now must conduct them every 36 months. In addition, the physical proximity criteria could result in a significant increase in the groups of substations evaluated, adding cost and time burdens. There is no technical justification or documented physical threat that supports the significant cost of evaluating and protecting these low-risk stations.	
Likes 1	Lincoln Electric System, 1, Johnson Josh

Dislikes 0	

Response

Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1 - RF	
Answer	No
Document Name	

Comment

The implementation of CIP-014-4 R2 and R3.5 as written (see comments above) will not be cost effective in terms of personnel and resources needed to address the physical security issues.

Likes 0	
Dislikes 0	

Response

Lucinda Bradshaw - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	

Comment

The cost impacts for the proposed changes to CIP-014-3 are expected to be minimal. Except as raised in the Comments above, the proposed changes add clarity to the current Standard to bring consistency to the risk assessment methodology, and clarify expectations for, effectively evaluating for instability, uncontrolled separation, and Cascading following a physical attack. The upper limit of cost added to entities is bounded due to no alteration of applicable substations potentially receiving security control upgrades. Rather, the cost incurred will be associated with the required additional study rigor, which again is anticipated to be relatively minimal.

Likes 0	
Dislikes 0	

Response

Kelley Sargent - Puget Sound Energy, Inc. - 3	
Answer	No
Document Name	

Comment

It is not clear to us if CIP-014-4 is cost effective to address reliability issue of physical security. Changes introduced in CIP-014-4 with respect to proximity criteria (R1 and R2) may result in additional stations becoming applicable for criticality assessment, thereby potentially increasing costs

Likes 0	
Dislikes 0	

Response

Rebika Yitna - Rebika Yitna On Behalf of: Roger Brand, MEAG Power, 3, 1; - Rebika Yitna

Answer	No
Document Name	

Comment

Performing the risk assessment every 36 months rather than every 60 months does increase the cost for Transmission Owners internally and for the cost of using an unaffiliated 3rd party to verify the risk assessment. Also, it is expected with the newly added adjacent station(s)/substation(s) requirement that this will incur a cost burden and will not be cost effective, if/when additional station(s)/substation(s) are added to the applicable list.

Likes 0	
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Tacoma Power supports the MRO NSRF comments, as follows.

It is too early in the process to effectively assess the cost considerations. However, these changes have the potential to add cost burden to smaller entities who fall under Attachment 1, Criterion 2.1, or those entities who previously completed studies every 60 months and now must conduct them every 36 months. In addition, the physical proximity criteria could result in a significant increase in the groups of substations evaluated, adding cost and time burdens. There is no technical justification or documented physical threat that supports the significant cost of evaluating and protecting these low-risk stations.

Likes 0	
Dislikes 0	

Response

Kevin Conway - Western Power Pool - 4

Answer	No
Document Name	

Comment	
No cost/benefit study has been provided to help determine cost effectiveness of CIP-014. So far, the implementation of CIP-014 has been very expensive to small utilities and has resulted in no proven cost savings. Quite the opposite, smaller entities have had problems with the auditing of CIP-014 and auditor subjectivity to assessments and risk analysis. In some cases, auditors did not agree with mitigation efforts or the quality of the mitigation efforts. CIP-014, in general, has also resulted in significant costs to entities who have qualified affiliates who can perform these threat assessments without the need to hire unaffiliated third-parties. Seattle City and Los Angelos, to name two, have their own police departments, investigative units, but are still required to hire an un-affiliated third party to review CIP-014 methodologies and security plans. Typically, this review is done by a less qualified third-party contractor that charges significant consulting rates to rubber stamp these plans.	
Likes 0	
Dislikes 0	
Response	
Matt Carden - Southern Company - Southern Company Services, Inc. - 1	
Answer	No
Document Name	
Comment	
Southern Company recognizes the financial impacts of performing the risk assessment every 36 months rather than 60 months for Transmission Owners that have not identified any Transmission stations or Transmission substations. This is magnified by the requirement to have an unaffiliated third party verify the risk assessment which does not provide a reliability benefit and no longer meets the original intent with the added specificity of the proposed standard.	
Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
Answer	No
Document Name	
Comment	
Don’t know what the “Cost” will be until the full scope of the requirement has been evaluated.	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	
It is too early to determine cost effectiveness impact.	
Likes 0	
Dislikes 0	
Response	

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	

Depending on the power system, stability may or may not be the only determining factor when identifying critical elements. System performance assessments that aim at determining critical elements of a system can only be conducted by an entity that possess the overall view and knowledge of the system behavior. As such, the Transmission Planners (TP) and/or Planning coordinators (PC) are the best suited entities to determine the critical elements of the power system under their responsibility.

We believe the application a performance-based methodology such as the NPCC A-10, as suggested by the drafting team, is a reliable, secure and cost-effective way to determine the scope of applicability where investments should be directed. However, the required efforts, technical knowledge and resources required to produce the resulting list of critical facilities are significant and cannot be justifiable, in our view, for the purposes of CIP-014 only, and can certainly not be performed by a transmission owner alone.

The current disparity among the different approaches currently used to establish the CIP-014 applicable facilities list assessment can be alleviated or practically eliminated by moving the responsibility of establishing the CIP-014 applicable facilities list to the Transmission Planners (TP) and/or Planning coordinators (PC).

The Transmission Planners (TP) and/or Planning coordinators (PC), should be required to provide a comprehensive methodology and uniform approach in determining the proper level of contingency applied to the system in their jurisdiction order to determine the CIP-014 applicable facilities list.

The Transmission Planners (TP) and/or Planning coordinators (PC) should be allowed to use past or related studies, using a uniform and justified contingency level to support the resulting facilities identified for applicability.

We suggest considering the following approach:

Keep the methodological approach of the current version of CIP-014 standard, where flexibility allows to account for disparity in determining factors associated power system architecture and behavior.

Make the Transmission Planners (TP) and/or Planning coordinators (PC) as the functional entities responsible for determining the list of critical facilities, instead of the current transmission owners.

Transfers the R1, R2 and R3 responsibility to the Transmission Planners (TP) and/or Planning coordinators (PC).

R3 should include a requirement for the Planning Coordinators to notify the transmission owners (TO) of any modifications to the CIP-014 applicable facilities list.

Likes 0	
Dislikes 0	

Response

Dave Krueger - SERC Reliability Corporation - 10

Answer	Yes
Document Name	

Comment

Thank you for the chance to comment, SERC appreciates the complexity of the SDT's task of modifying multiple parts of such a high-profile and high-priority standard. While we generally agree CIP-014-4 is a cost effective approach, additional methods to improve its cost effectiveness are suggested in Item #Additional.A below under 'additional comments'

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	Yes
Document Name	

Comment	
FirstEnergy has no issue with the cost effectiveness of this proposed standard.	
Likes 0	
Dislikes 0	
Response	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO, Group Name Manitoba Hydro Group	
Answer	Yes
Document Name	
Comment	
Manitoba Hydro notes that there is an opportunity to make the standard more efficient by clearly outlining when risk based studies are required and what types of studies are required.	
Likes 0	
Dislikes 0	
Response	
Zenon O'young-Chu - Seattle City Light - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Shultz - Seattle City Light - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Jang - Seattle City Light - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1,3,5	
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 NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Baldwin - James Baldwin On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - James Baldwin	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Fon Hiew - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Shafer - New York State Electric & Gas (NYSEG) - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michele Tondalo - United Illuminating Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Tyler Schwendiman - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	

Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren has no comment on cost effectiveness of the project to address the reliability issue.	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	
Document Name	
Comment	
MRO is not in a position to assess the cost aspect.	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	

Louisville Gas & Electric and Kentucky Utilities support EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	
Document Name	
Comment	
NEE does not comment on cost.	
Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	
Document Name	
Comment	
No Comment	

Likes 0	
Dislikes 0	
Response	

9. Provide any additional comments for the standard drafting team to consider, if desired.

Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	
- There were several references within the Violation Severity Levels section that don't seem to be pointing to the correct parts of the document. The Violation Severity Levels section needs to be reviewed to make sure it's pointing to the correct sections. - Idaho Power questions the requirement for proximity stations being studied as simultaneous SLG faults at the highest bus of both stations. We wonder if that will always be the right study for a physical attack on a station in proximity as it really depends on how proximity stations are defined and what the configuration of the station is in each instance.	
Likes 0	
Dislikes 0	
Response	

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	
Document Name	
Comment	
• There needs to be a process to remove stations from critical list if in future assessments it is deemed non-critical. • R6. Increase unaffiliated third party verification timeline from 90 calendar days to 180 calendar days to accommodate additional study work being required by CIP-014-4. • Clarify if a critical site is not re-evaluated per R3.2.2 and R5.1, is an evaluation of threats and vulnerabilities still required per new R8?	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Western Power Pool - 4	
Answer	
Document Name	
Comment	
The Drafting Team should be commended for taking on the responsibility to rework CIP-014. It has a significant challenge ahead of it to ensure that a majority of entities agree with the changes. CIP-014 has had its problems, and the Drafting Team should ensure that not only is FERC's directive met for this standard, but that problems related to the original versions of CIP-014 are addressed. The Drafting Team should focus on auditable, enforceable	

and objective requirements that enhance reliability and do not result in compliance risk and costs to entities that is not commensurate to the overall risk the entity represents to the BPS.

Likes 0	
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	
Document Name	

Comment

Tacoma Power supports the MRO NSRF comments, as follows.

The MRO NSRF appreciates the work the SDT has done on this first draft of CIP-014-4 and offers the following additional comments.

First, the MRO NSRF recommends the SDT eliminate R6, the third party verification for the risk assessment. While this elimination is not explicitly mentioned in the SAR, it is directly tied to the changes proposed in the SAR. The purpose of the third party verification goes away with the increased prescriptiveness of the risk assessment proposed in R3. In addition, since the SAR indicates that industry was not implementing a consistent approach to the risk assessments, then that indicates the third party verifications were also proving to be of little value. This independent verification is a burdensome and costly endeavor that has not proven to be value-added. In many compliance monitoring activities, the verification Requirement is not audited or considered by monitoring personnel. Planning this task with eligible vendors requires significant work to coordinate and thousands of dollars to complete. Given that the verifications exist solely to offer feedback on an approach which will no longer be required with the increased specificity in R3, then their removal would eliminate what has become an unnecessary administrative burden.

Second, the MRO NSRF is concerned that if implemented, the expansion of CIP-014 beyond a single entity makes compliance almost unattainable. The remainder of the Requirements after the R5 Risk Assessment could require an entity to assess threats and vulnerabilities and protect BES Elements that is does not own or operate.

In regards to the Applicability changes, consider a small entity that has no current CIP-014 applicable stations, but has a station adjacent to another entity's larger Transmission Facility that is just under the Applicability threshold on its own. In this case the small entity would now have to create a list for R1 that includes that small station. Then both entities would confirm those same stations through R2 adjacency criteria (duplicative). They would eventually get to the R5 risk assessment performance requirement and conduct an overlapping risk assessment.

The small entity could end up with a list of stations whose loss could result in instability, uncontrolled separation, or Cascading within an Interconnection. The challenge with this situation is that the list will likely contain stations where the real risk is with the station that is not owned or operated by the entity performing the Risk Assessment.

What does this mean for compliance with CIP-014? What does the small entity do to comply with R6-R10? Will this small entity be responsible for assessing threats and vulnerabilities of the large Transmission facilities that they do not own or operate? Are they then responsible for providing security protections for these same stations?

The MRO NSRF recommends that prior to expanding the scope of CIP-014 to include these adjacent facilities either through the drafted 2.1 applicability criteria, or physical proximity criteria as part of a risk assessment methodology, that NERC solicit further information from the industry to determine if a significant risk exists. Similar to Project 2021-03 for TOCCs, it would be beneficial to have a study to analyze the number of impacted sites, the aggregate risk of not including for these locations, and conclusions as to whether regulatory action is needed to address the residual risk.

Finally, the MRO NSRF also recommends the following adjustments to the proposed VSL tables:

1. VSL table “CIP-014-3” should be “CIP-014-4”

2. The VSLs as written are overly prescriptive and don’t reflect reliability risks. For example:

a. For R4 – Request that the drafting team review the number of VSL against the reliability risk of R4. There seem to be too many VSL compared to the actual reliability risks.

b. For R5 – Suggest that lower VSL should be for an assessment performed between 36 and 42 months and severe if greater than 42 months (assumed not at all). Every TO by now has done more than one assessment. Typically the system doesn’t change much over a 3 year time span so that any critical facilities previously identified wouldn’t change. Delaying an assessment a few months is not a severe detriment to reliability.

Likes 0	
Dislikes 0	

Response

Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO, Group Name Manitoba Hydro Group

Answer	
Document Name	

Comment

MH believes the third-party verification requirement is unnecessary for this standard, so it is recommended that SDT consider removing it. Instead, the standard can be updated to share the assessment reports with adjacent TOs identified as having stations in close vicinity or jointly owned facilities.

Likes 0	
Dislikes 0	

Response

Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova

Answer	
Document Name	

Comment

We see that NERC SDT is targeting to mimic the NPCC A-10 Identification methodology which is system performance-based. Simulated system performance-based identification methodology is not well suited to this Physical Security standard; it is out of scope.

There is great merit for NERC to review transition to using performance-based methodology for identifying critical elements of the bulk power system. Please keep in mind that the Reliability Coordinators and Transmission Planners are best suited to run these types of studies because have they have broad oversight of their entire footprint, which is needed for this type of determination. Certainly, individual TO’s do not have sufficient tools and knowledge to run NPCC A-10 type studies. This said, we believe there is great merit in NERC considering simulated system performance-based critical infrastructure identification methodology. This identification could flow smoothly into TLP-001 analysis.

For this physical security standard, a practical option for the SDT to consider for physical criticality determination is:

- Start with NERC BES as defined considering inclusions and exclusions
- Then filter by those facilities used in an IROL definition (can be provided by the RC or TP)
- Add in tie-lines that meet criteria: e.g. used for import/export and relied upon to balance area footprint during a significant loss of generation or loss of load event (can be provided by the RC or TP)
- Add in critical stations hubs that supply a significant/critical regional load pocket (can be provided by the RC or TP or TO)
- Add in stations directly connected to nuclear facilities – the station(s) that the nuclear facility generates into before flow disperses
- Then filter by physical threats as this is a physical security standard.

The idea here is that a TO would use readily available information for R1 & R3.

In alternative:

Suggestion to reword 3.1.1 to not be prescriptive on 12 individual study items in the standard. Something along the line of, " ...TO must demonstrate suitable dynamic studies to identify critical stations. It would then be up to the TO to have documentation to pass to auditor which will comprise of dynamic studies, and/or justification why certain ones were omitted.

Likes 0	
Dislikes 0	

Response

Kelley Sargent - Puget Sound Energy, Inc. - 3

Answer	
Document Name	

Comment

It is not clear the type of events CIP-014-4 intends to address that can simultaneously impact 2 or more stations. The standard depends on physical security measures to mitigate such events, however mitigation to the extent may not be feasible nor cost effective.

Likes 0	
Dislikes 0	

Response

Lucinda Bradshaw - Oncor Electric Delivery - 1 - Texas RE

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1 - RF

Answer	
Document Name	

Comment

NIPSCO's position is that the changes to the CIP-014 standard as written improve the Physical Security Standard. However, the current draft would implement many unknown and potentially costly measures to include transmission substations that are not owned by NIPSCO but within "line of sight" of NIPSCO's applicable transmission stations/substations.

Likes 0	
Dislikes 0	

Response

Tyler Schwendiman - ReliabilityFirst - 10

Answer	
Document Name	

Comment

For R6.1, is the intent to review the risk assessment was performed accurately? If yes, what would a planning-based risk assessment (and having planning experience) have to do with evaluating security measures implemented at the substation to mitigate the risk?
For 6.1.2, what would be an adequate level of transmission planning or analysis experience. This seems ambiguous.
For 6.2 and 6.3, again, it seems that verification efforts of the risk assessment (planning oriented) and physical security recommendations are being mixed here.
In general, consideration needs to be given for "smoking hole" attacks (in which three-phase faults would represent) cannot be completely mitigated through physical security upgrades. In reality, physical security measures will more likely delay, detect, and improve response time for these attacks. What criteria should be used to measure improved physical security posture? In addition, the attack vector of transmission elements outside of the substation would remain vulnerable even after substation physical enhancements are made.

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter

Answer	
Document Name	

Comment

While previously addressed, FirstEnergy is including the following requests:

Requirement 4 states “owned Transmission station(s) and Transmission substation(s) shall coordinate to determine and identify each entity’s individual and joint responsibilities for performing any required risk assessments…” but the VSL for this requirement states “ The Transmission Owner performed a risk assessment but…” with no mention of coordination. FirstEnergy requests synching the intent of the Requirement with the VSL.

Further, the VSL for R5 appears to be a copy-and-paste of R5. FirstEnergy requests edits to synchronize the intent of R5 with the VSL.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	
Document Name	

Comment

The MRO NSRF appreciates the work the SDT has done on this first draft of CIP-014-4 and offers the following additional comments.

First, the MRO NSRF recommends the SDT eliminate R6, the third party verification for the risk assessment. While this elimination is not explicitly mentioned in the SAR, it is directly tied to the changes proposed in the SAR. The purpose of the third party verification goes away with the increased prescriptiveness of the risk assessment proposed in R3. In addition, since the SAR indicates that industry was not implementing a consistent approach to the risk assessments, then that indicates the third party verifications were also proving to be of little value. This independent verification is a burdensome and costly endeavor that has not proven to be value-added. In many compliance monitoring activities, the verification Requirement is not audited or considered by monitoring personnel. Planning this task with eligible vendors requires significant work to coordinate and thousands of dollars to complete. Given that the verifications exist solely to offer feedback on an approach which will no longer be required with the increased specificity in R3, then their removal would eliminate what has become an unnecessary administrative burden.

Second, the MRO NSRF is concerned that if implemented, the expansion of CIP-014 beyond a single entity makes compliance almost unattainable. The remainder of the Requirements after the R5 Risk Assessment could require an entity to assess threats and vulnerabilities and protect BES Elements that is does not own or operate.

In regards to the Applicability changes, consider a small entity that has no current CIP-014 applicable stations, but has a station adjacent to another entity’s larger Transmission Facility that is just under the Applicability threshold on its own. In this case the small entity would now have to create a list for R1 that includes that small station. Then both entities would confirm those same stations through R2 adjacency criteria (duplicative). They would eventually get to the R5 risk assessment performance requirement and conduct an overlapping risk assessment.

The small entity could end up with a list of stations whose loss could result in instability, uncontrolled separation, or Cascading within an Interconnection. The challenge with this situation is that the list will likely contain stations where the real risk is with the station that is not owned or operated by the entity performing the Risk Assessment.

What does this mean for compliance with CIP-014? What does the small entity do to comply with R6-R10? Will this small entity be responsible for assessing threats and vulnerabilities of the large Transmission facilities that they do not own or operate? Are they then responsible for providing security protections for these same stations?

The MRO NSRF recommends that prior to expanding the scope of CIP-014 to include these adjacent facilities either through the drafted 2.1 applicability criteria, or physical proximity criteria as part of a risk assessment methodology, that NERC solicit further information from the industry to determine if a significant risk exists. Similar to Project 2021-03 for TOCCs, it would be beneficial to have a study to

analyze the number of impacted sites, the aggregate risk of not including for these locations, and conclusions as to whether regulatory action is needed to address the residual risk.

Finally, the MRO NSRF also recommends the following adjustments to the proposed VSL tables:

1. VSL table “CIP-014-3” should be “CIP-014-4”

2. The VSLs as written are overly prescriptive and don’t reflect reliability risks. For example:

a. For R4 – Request that the drafting team review the number of VSL against the reliability risk of R4. There seem to be too many VSL compared to the actual reliability risks.

b. For R5 – Suggest that lower VSL should be for an assessment performed between 36 and 42 months and severe if greater than 42 months (assumed not at all). Every TO by now has done more than one assessment. Typically the system doesn’t change much over a 3 year time span so that any critical facilities previously identified wouldn’t change. Delaying an assessment a few months is not a severe detriment to reliability.

Likes 1	Lincoln Electric System, 1, Johnson Josh
Dislikes 0	

Response

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB

Answer	
Document Name	

Comment

Regarding requirements R2 and R3, proximity and event definition should be foundationally based in reality and practicality. Functional Entities should have the latitude to determine potential events that may occur on their system or in their area. Furthermore, it is generally beyond the skillset of planning engineers, who complete CIP-014-4 studies, to determine what types of attack may impact one or multiple stations. Risk assessments, completed by security professionals, based on things like location, historical events, and current threats should be utilized to define event scope instead of planning engineers. Using this methodology would further drive the accuracy and applicability of CIP-014-4 event simulations.

Likes 0	

Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Insitute (EEI) and MRO NSRF for question #9.	
Likes 0	
Dislikes 0	
Response	
Leshel Hutchings - AEP - 3	
Answer	
Document Name	
Comment	
There is a typo in R8 Section 8.3 which could be corrected in this revision. “Electricity Sector Information Sharing and Analysis Center (ES-ISAC)” should say “Electricity Information Sharing and Analysis Center (E-ISAC)”. AEP’s comments to the draft requirement changes would necessitate the need to change the VSL table.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
It appears the revisions do not address the fundamental flaw with CIP-014: there is no language to guide or require entities to frame the study that is used as the risk assessment around a specific physical security scenario or threat vector(s). Being vector-agnostic is failing to bridge the divide	

between the different missions of transmission planners and physical security experts. Uncertainty remains about what is supposed to be studied ("smoking hole dilemma"), especially when compared with considerations of how likely or realistic certain threat vectors appear to be.

BPA believes there is still bias in the language toward adding physical security treatments to sites that will forever stay on the list, when system redesign, presence of Remedial Action Schemes, etc. could be used to reduce the criticality of a site.

BPA believes there is still subjectivity due to the lack of a clear and precise definition for "critical" and "primary control center".

The revisions appear to be moving in the direction of increasing the number of CIP-014 sites, when the original intent of the standard was to have a very small number of sites.

Likes 0	
Dislikes 0	

Response

Karen Demos - NextEra Energy - Florida Power and Light Co. - 3

Answer	
Document Name	

Comment

NextEra/FPL supports EEI's comments

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	
Document Name	

Comment

WAPA appreciates the work the SDT has done on this first draft of CIP-014-4. WAPA concurs with the additional comments provided by the MRO NSRF and offers the following additional comments.

The "clean" version of the drafted Standard posted on the project page is different than the "redline" version. Compare R6 as the example between the two posted versions.

Additionally, WAPA strongly recommends the SDT eliminate R6, the third party verification for the risk assessment. WAPA agrees with the reasons already proposed by the MRO NSRF, but also because it holds the entity responsible for the actions of another organization, and creates the risk of non-compliances when a separate reviewer fails to complete their work on time.

While this elimination is not explicitly mentioned in the SAR, it is directly tied to the changes proposed in the SAR. The purpose of the third party verification goes away with the increased prescriptiveness of the risk assessment proposed in R3. In addition, since the SAR indicates that industry was not implementing a consistent approach to the risk assessments, then that indicates the third party verifications were also proving to be of little value. This independent verification is a burdensome and costly endeavor that has not proven to be value-added. Planning this task with eligible vendors requires significant work to coordinate and thousands of dollars to complete. Given that the verifications exist solely to offer feedback on an approach which will no longer be required with the increased specificity in R3, then their removal would eliminate what has become an unnecessary administrative burden.

Likes 0	
Dislikes 0	

Response

Michael Dillard - Austin Energy - 5, Group Name Austin Energy

Answer	
Document Name	

Comment

Austin Energy supports MRO's comments. Attached in Question 1.

Likes 0	
Dislikes 0	

Response

Anne Kronshage - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County - Voting Group

Answer	
Document Name	

Comment

As noted above multiple times, NERC may wish to consider how to provide an incentive to utilities to think of ways to get stations de-classified. In TPL-001-5, the concept of Corrective Action Plan is used; in the current form of CIP-014, the corrective action plan does not contemplate the potential of system-level fixes (such as modifications to far-end protection), but instead jumps to the assumption that physical security is the only solution and the system is 'stuck' with the instability, cascading, or uncontrolled separation risk. This is not necessarily the case.

The layout of the proposed steady state and stability requirements read 'clunky'; in TPL-001-5, R3 clearly addresses the steady state simulation requirements and simulation expectations; R4 clearly addresses the stability simulation requirements and simulation expectations. This separation in TPL-001-5's presentation allowed for greater clarity, whereas the current proposed draft of CIP-014 combines its steady state and stability requirements in overlapping sections of R3.

The requirement under the proposed R3.1.2 "Technically supported thresholds for acceptable load loss and acceptable generation loss" is something that has been a regulatory discussion for years, with not a lot of firm guidance or clarity, such as a 1000 MW bright-line. The current CIP-014 has not provided much in the way of example or guidance for utilities to clarify what is expected here either, neither in the proposed revision itself or in the technical rationale (a little bit of guidance is noted here, but this is not sufficient). These would likely be big numbers for a large load-serving utility; conversely, these would be small numbers for a small utility. "Whose load or generation" becomes a further point, as does steady state vs. stability model load loss (such as composite load model load drop in WECC), consequential vs. non-consequential loss, and customer counts vs load loss (for example, 1000 MW at peak load is likely a different level of customer impact than loss of 1000 MW during an off-peak condition). As such, this language will likely result in furthering the spread of differences for methods and assumptions used in CIP-

014 assessments. Since the proposed requirement and its outcome doesn't appear to support the Project Scope objectives and these methodology differences will exist regardless of this language, it is recommended R3.1.2 be removed.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	
Document Name	
Comment	
NEE support's EEI comments: "For efficiency and to avoid revising CIP-014-4 as part of project 2021-03, please consider coordinating with project 2021-03 to edit the IROL wording in CIP-014 now as part of project 2023-06. Please consider revising Attachment 1, item 3: "3. Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies." to read as, "3. Transmission Facilities at a single station or substation location that are identified by its Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event."	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	

Comment	
Tri-State agrees with the MRO NSRF Submitted Comments under Additional Comments	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation agrees with the following EEI comment: For efficiency and to avoid revising CIP-014-4 as part of project 2021-03, please consider coordinating with project 2021-03 to edit the IROL wording in CIP-014 now as part of project 2023-06. Please consider revising Attachment 1, item 3: "3. Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies." to read as, "3. Transmission Facilities at a single station or substation location that are identified by its Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event."	
Likes 0	
Dislikes 0	
Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy supports EEI's additional comments.	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	
Document Name	
Comment	
Dominion Energy supports EEI's additional comments. Also, Dominion Energy is of the opinion that resources to gather the required information and to perform the required studies are highly specialized and not readily available. Internal expertise continues to be a challenge to obtain, and vendors are very limited in their abilities and bandwidth.	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	
Document Name	
Comment	

R6.2: Eversource requests R6.2 allow for 90 days instead of 60 so proper work can be completed. With a more detailed analysis being required, there is a higher chance of disagreement with our third party reviewer, requiring more time needed for response.

R7: Eversource requests the removal of "is not under the operational control of the Transmission Owner " in R7. Regardless if the facility is owned by the company that operates the facility, the Transmission Operator should be notified as the group doing the CIP-014 assessment and the group operating the system should be required to communicate.

Technical Rationale Comments:

Requirement 2 – Eversource has concern with the phrase "certain amount of discretion and flexibility is intended to be allowable for each Transmission Owner" as the "flexibility" often leads to disagreement with an auditor if the interpretations do not much either.

Requirement 3, Part 3.1 – Rationale spelled wrong. Also, Eversource agrees there should be flexibility around load loss as it will vary within the interconnection, but the system frequency allowed should be standardized throughout the interconnection.

Requirement R3, Part 3.3 – Rationale does not line up with what is in standard, appears to be missing.

Requirement R3, Part 3.4 – Why not a three-phase fault at all transmission buses within a single Transmission station or Transmission substation?

Requirement R3, Part 3.5 – Why not a three-phase fault at all transmission buses within a single Transmission station or Transmission substation?

Requirement R3, Part 3.6 - Eversource fully supports this.

Requirement R3, Part 3.6.1 – Eversource fully supports this.

Likes 0	
Dislikes 0	

Response

Andrew Smith - APS - Arizona Public Service Co. - 5

Answer	
Document Name	

Comment

AZPS seeks to understand the complete responsibilities for transmission stations within proximity of an applicable station which has been deemed critical under the risk assessment. As written, the draft could be interpreted to mean that entities must conduct the risk assessment on stations which are not owned or operated by the entity. It is not clear what responsibilities the entity has when the substation is not jointly owned. The draft team should clarify all considerations for a transmission station identified as “within proximity” but not owned by the entity.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	
Document Name	

Comment

Louisville Gas & Electric and Kentucky Utilities support EEI's comments.

Likes 0	
Dislikes 0	

Response

Dave Krueger - SERC Reliability Corporation - 10

Answer	
Document Name	

Comment

Thank you for the chance to comment, SERC appreciates the complexity of the SDT's task of modifying multiple parts of such a high-profile standard.

· Item #Additional.A: Consider editing requirement CIP-014-4 R6.2 indicating that the details of the R2 proximity criteria/analysis, R3 risk assessment methodology, and R5 risk assessment completion be provided to the third-party verifier. Given the new breadth of components in R1, R2, R3, and R5, these materials would undoubtedly be needed for the Third-Party Verifier(s) to fully review the Responsible Entity's performance. This aids in fulfillment of SAR Scope Item #3, "Assure the adequacy and consistent implementation of technically supported justification for study decisions" as the R2 Third Party Verifier is the timely and primary control to provide feedback that R1-R5 implementation was consistent, and if any recommendations or changes bear consideration.

· Item #Additional.B Consider editing requirement CIP-014-4 R6.4 to indicate that the R2 proximity criteria, R3 risk assessment methodology, and R5 risk assessment completion be made available to the personnel performing the R8 threat/vulnerability evaluation, and the R9 security/resiliency plans without running afoul of information protections. Security and resilience measures will be planned, prioritized, and implemented with higher effectiveness and precision if the specific knowledge of the types of contingencies, types of cases/BES situations studied, and the results of what specific methodology results failed are provided. This will enable the personnel performing R8 and R9 to better design the security and resiliency measures for specific threat/vulnerability scenarios which would specifically lead to the 'Evil 3', instead of assumed or generically considered threat/vulnerability exploitation. It should be made clear in either the requirement language or implementation guidance that sharing this information in order to develop mission and cost-effective resiliency and security measures is expressly permitted under R6.4 (and R9.4). Doing this will reduce the deployment of generic and less-effective measures which do not effectively reduce or otherwise mitigate the risk of instability, uncontrolled separation, or Cascading due to the loss of critical sites. This would aid in fulfillment of SAR Scope Item #4, "Clarify what study scenario(s) and other study assumptions are appropriate and reasonable considering the intent of CIP-014-3 and the potential range of issues during a physical attack. Simulations should incorporate the loss of station elements without local system protection."

Likes 0	
Dislikes 0	

Response

Jeffrey Streifling - NB Power Corporation - 1

Answer	
Document Name	

Comment

Request R6.2 allow for 90 days instead of 60 so proper work can be completed. With a more detailed analysis being required, there is a higher chance of disagreement with a third party reviewer, requiring more time needed for response.	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	
Document Name	
Comment	
The Technical Rationale has a heading of "PRC-002-4 Technical Rational" when opened in Adobe Acrobat. In the clean version of the draft CIP-014-4 R6.1 appears to be a copy of CIP-014-3 R5.1. The redline version of CIP-014-4 R6.1 appears correct	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	
Document Name	
Comment	
Request R6.2 allow for 90 days instead of 60 so proper work can be completed. With a more detailed analysis being required, there is a higher chance of disagreement with a third party reviewer, requiring more time needed for response.	
Likes 0	
Dislikes 0	
Response	
Fon Hiew - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	

Answer	
Document Name	
Comment	

Request R6.2 allow for 90 days instead of 60 so proper work can be completed. With a more detailed analysis being required, there is a higher chance of disagreement with a third party reviewer, requiring more time needed for response.

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	
Comment	

Minnesota Power supports MRO-NSRF and EEI's comments.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer	
Document Name	
Comment	

Ameren supports EEI's comments on this project.

Likes 0	
Dislikes 0	

Response

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment	
For efficiency and to avoid revising CIP-014-4 as part of project 2021-03, please consider coordinating with project 2021-03 to edit the IROL wording in CIP-014 now as part of project 2023-06. Please consider revising Attachment 1, item 3: “3. Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.” to read as, “3. Transmission Facilities at a single station or substation location that are identified by its Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event.”	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	
Document Name	
Comment	
• The analysis criteria and the expectation for the TO to perform an analysis needs to be removed from this standard and addressed in TPL space. This and the inclusion of more prescriptive study criteria (in the correct standard category) mitigates the need for third-party verification of the analysis. • Currently the third-party verifications referenced in the standard are not subject to NERC requirements. An assessment could receive favorable third-party verification but still not meet the requirements of the standard in the opinion of a regulatory entity. • R8 – R10 may require modification in response to stated comments on R3 & R5.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Eclectic Institute	

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	
Document Name	

Comment

Request R6.2 allow for 90 days instead of 60 so proper work can be completed. With a more detailed analysis being required, there is a higher chance of disagreement with a third party reviewer, requiring more time needed for response.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1, Group Name Exelon

Answer	
Document Name	

Comment

For efficiency and to avoid revising CIP-014-4 as part of project 2021-03, please consider coordinating with project 2021-03 to edit the IROL wording in CIP-014 now as part of project 2023-06.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	
Document Name	

Comment

NV Energy supports EEI's additional comment response.

Likes 0	

Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
MISO notes that expanding R2 to encompass "Transmission substation(s) in proximity to those identified in Requirement R1, *irrespective of ownership*" introduces a timing issue that must be addressed in verifying CIP-014 risk assessments. As CIP-014 requires risk assessment verifications to be complete within 90 calendar days (pursuant to CIP-014, Part 6.2), MISO asks the SDT to establish a timeline by which entities owning proximate substations are required to respond to communications from Transmission Owners and unaffiliated third parties performing risk assessments. This will ensure information is provided in a timely manner as at least some owners of proximate substations will not otherwise be subject to CIP-014.	
Likes 0	
Dislikes 0	
Response	
Michael Jang - Seattle City Light - 1	
Answer	
Document Name	
Comment	
In agreement and support of SCL SME's additional comments: With the changes to R3 providing more explicit direction on how to perform the risk assessment, 3rd party verification seems unnecessary, so R6 can be eliminated. It wasn't clear that the 3rd party verifications were effective in the first place. If R6 is maintained, the first sentence of R6.1 and of R6.3 are incomplete and should be rewritten.	
Likes 0	
Dislikes 0	
Response	
Chris Shultz - Seattle City Light - 5	
Answer	
Document Name	

Comment	
With the changes to R3 providing more explicit direction on how to perform the risk assessment, 3rd party verification seems unnecessary, so R6 can be eliminated. It wasn't clear that the 3rd party verifications were effective in the first place. If R6 is maintained, the first sentence of R6.1 and of R6.3 are incomplete and should be rewritten.	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	
Document Name	
Comment	
See EEI comments	
Likes 0	
Dislikes 0	
Response	
Robert Jones - Seattle City Light - 4	
Answer	
Document Name	
Comment	
With the changes to R3 providing more explicit direction on how to perform the risk assessment, 3rd party verification seems unnecessary, so R6 can be eliminated. It wasn't clear that the 3rd party verifications were effective in the first place. If R6 is maintained, the first sentence of R6.1 and of R6.3 are incomplete and should be rewritten.	
Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 6	
Answer	
Document Name	

Comment	
With the changes to R3 providing more explicit direction on how to perform the risk assessment, 3rd party verification seems unnecessary, so R6 can be eliminated. It wasn't clear that the 3rd party verifications were effective in the first place. If R6 is maintained, the first sentence of R6.1 and of R6.3 are incomplete and should be rewritten.	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	
ITC supports both the additional comments of EEI and MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
Answer	
Document Name	
Comment	
PNM and TNMP support EEI additional comments, noted again here. Additionally, a **SAR** should be considered to revise CIP-014-4 R6 to allow additional time for third party verification, especially if prescriptive study criteria are not included in the standard. *"For efficiency and to avoid revising CIP-014-4 as part of project 2021-03, please consider coordinating with project 2021-03 to edit the IROL wording in CIP-014 now as part of project 2023-06. Please consider revising Attachment 1, item 3: "3. Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies." to read as, "3. Transmission Facilities at a single station or substation location that are identified by its Planning Coordinator or Transmission Planner, per its Planning Assessment of the Near-Term Transmission Planning Horizon as a Facility that if lost or degraded are expected to result in instances of instability, Cascading, or uncontrolled separation that adversely impacts the reliability of the Bulk Electric System for a planning event."*	
Likes 0	
Dislikes 0	
Response	

Zenon O'young-Chu - Seattle City Light - 3	
Answer	
Document Name	
Comment	
With the changes to R3 providing more explicit direction on how to perform the risk assessment, 3rd party verification seems unnecessary, so R6 can be eliminated. It wasn't clear that the 3rd party verifications were effective in the first place. If R6 is maintained, the first sentence of R6.1 and of R6.3 are incomplete and should be rewritten.	
Likes 0	
Dislikes 0	
Response	
Jason Snodgrass - Jason Snodgrass On Behalf of: Katrina Lyons, Georgia System Operations Corporation, 3, 4; - Jason Snodgrass	
Answer	
Document Name	
Comment	
GSOC supports comments provided by Georgia Transmission	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
WECC voted negative on the non-binding poll for various reasons identified in the comments below. WECC appreciates the efforts to improve reliability and security by the changes proposed. Although the changes may be considered significant (both the original language and language proposed), the risk is real and the threat vectors continue to increase. WECC supports the direction but clarity around the language will help ensure consistent application of the Requirements. We propose that the language regarding "line of sight" and "ease of access to a common public roadway" should provide more detailed and specific guidelines to clearly define how entities can achieve security AND compliance. Providing expectations and requirements will not only help entities understand the necessary steps and measures needed to meet the Standard but also ensure consistency across CMEP teams. This approach will help avoid the development of varying audit approaches and interpretations, leading to a more uniform and fair audit. Reliability and security should be considered foundational attributes of the electrical grid and	

achieving the level commensurate with the risk is probably viewed differently across the industry. Events that may be avoided through effective risk mitigation should be a goal of this project.

Capitalize "control center" in the Purpose statement. Extra period at end of Requirement R2 needs removed. Requirement 6 in the red-lined version is different than the Requirement 6 language in the clean version. The clean version has additional language in Requirement 6.1 and 6.3 that was moved to Requirement 9. Updated Requirement 6.2 needs to change "R1" to "R5" in first sentence referencing the performance of the risk assessment. Should "Control Center" be added to Requirement 6.2 and 6.3 as the deletion/addition of a Transmission station or Transmission substation could affect Control Center identification? Consider adding "as critical" after "its identification" to provide clarity in Requirement 6.3. Measure M6 should only reference R5 identification and not any additional modifications as the third-party is only verifying the R5 risk assessment and not the list of Transmission station(s) and Transmission substation(s). If the intent is to verify all applicable Transmission station(s) and Transmission substation(s) called out in R1, R2 (unless subsumed- see previous comments), and R4 then language needs added to Requirement R6 to allow such a change. R7 needs to capitalize "control center" as discussed previously. Use NERC defined terms for clarity and consistency. Requirement R7.1 should only reference R5 not "R1, R2, R3, R4 and R5" as R5 is where Transmission station(s) and Transmission substation(s) are identified (suggest adding "as critical" as well here to be clear) through the risk assessment being verified. Requirement R7.1 incorrectly references R1 (should be R5) and incorrect changed R2 to R5 when that reference should be R6 (verification by third-party). Capitalize "control center" in R8. Need to correctly reference E-ISAC by changing "the Electricity Sector Information Sharing and Analysis Center (ES-ISAC" to "the Electricity Information Sharing and Analysis Center (E-ISAC)" in R8. Capitalize "control center" in R9. Measure M9 needs to reference Requirement R9 not Requirement R6.

Evidence retention should mirror the periodicity or go beyond the periodicity of the Requirement language (e.g. 36 calendar months not 3 years).

VSL header needs to change reference to CIP-014-4 not "-3". VSL language for R1 reflects "calendar months" but Requirement R1 language simply says "months". VSL language for R1 misses the inclusion of R4 in terms of applicable Transmission station(s) and Transmission substation(s). Furthermore, the VSL should not delve into a percentage missing as the only way an auditor could determine that is a complete list of all Transmission station(s) or Transmission substation(s) be provided (including those in close proximity per R2 and "jointly owned" in R4). The percentage basically indicates a reperformance by CMEP staff in the determination of applicable Transmission station(s) and Transmission substation(s). RSAW may provide an internal control question to have the entity show how it ensures inclusion. Certainly the entity should have a list of all Transmission stations and Transmission substations with an inventory of fully owned and those stations where partial ownership exists. As for the proximity of substations, clear indication of why they were included should be maintained. Verification of proximity from a compliance perspective may require review of internal controls coupled with site visits or use of Google Earth (as an example).

High VSL for R2 should not use the term "insufficient". There are 3 criterion listed in R2 so consider indicating the missing of one of the three required criterion as basis for High VSL.

VSLs for Requirement R3 may need to change if formatting suggestion is applied (note R3.3. says "Analysis of fault simulations, as follows: "and R3.4 and R3.5 should be sub bullets of R3.3).

R4 VSLs do not correspond with Requirement R4 language (no risk assessment performed in R4, no subparts of R4). Should reference the failure to coordinate at least once every 36 months in some manner. Consider keeping the first part of each VSL but replace "performed a risk assessment" to "did not coordinate to determine and identify responsibilities associated with required risk assessments but did so after ….." Additionally, R4 is not bulleted so unclear what the DT is trying to reference here for R4.

R5 VSLs may need to address references to R3 parts if formatting is corrected in R3. Additionally, R4 is not bulleted so unclear what the DT is trying to reference here for R4.

R6 VSLs need some adjustments. Consider the following:

R6 Lower VSL-"The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R4R5, but did so in more than 90 calendar days, but less than or equal to 100 calendar days following completion of Requirement R4R5. OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R4R5 and modified or documented the technical basis for not modifying its identification under Requirement R4R5 as required by Part 6.35.2 but did so more than 60 calendar days and less than or equal to 70 calendar days from completion of the third party verification."

Moderate VSL--"The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R4R5, but did so in more than 100 calendar days, but less than or equal to 110 calendar days following completion of Requirement R4R5. OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R4R5 and modified or documented the technical basis for not modifying its identification under Requirement R4R5 as required by Part 6.35.2, but did so more than 70 calendar days and less than or equal to 80 calendar days from completion of the third party verification."

High VSL-"The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R4R5, but did so in more than 110 calendar days, but less than or equal to 120 calendar days following completion of Requirement R4R5. OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R4R5 and modified or documented the technical basis for not modifying its identification under Requirement R4 as required by Part 6.35.2, but did so more than 80 calendar days from completion of the third party verification. OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R4R5, but failed to modify or document the technical basis for not modifying its identification under R4R5 as required by Part 6.35.2."

Severe VSL-"The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R4R5, but did so more than 120 calendar days following completion of Requirement R4R5. OR The Transmission Owner failed to have an unaffiliated third party verify the risk assessment performed under Requirement R4R5. OR The Transmission Owner had an unaffiliated third party verify the risk assessment performed under Requirement R4R5, but failed to implement procedures for protecting information per Part 6.45.2."

R7 VSLs should reference R7 not R6 (R6 shown as replacement for R3) or alternatively say "…as identified in Requirement R5 but…" or alternatively say "…as verified in Requirement R6.." instead of "as specified in Requirement R63 but.." Additionally, later in the VSLs, change the Requirement R1 to R5 (versus R4).

R8 VSLs-Responsible Entity is not defined. Understand the desire to avoid repeating TO and/or TOP. Consider lower-casing the use of the term in the VSLs. Change the Requirement R1 reference to R5 (versus R4). The VSLs should reference Parts 8.1 through 8.3 versus 7.1 through 7.3.

R9 VSLs- -Responsible Entity is not defined. Understand the desire to avoid repeating TO and/or TOP. Consider lower-casing the use of the term in the VSLs. Change the Requirement R1 reference to R5 (missed it completely in the Lower VSL while others reference Requirement R4.) It appears that the development and implementation should not occur until after verification in Requirement R6 versus Requirement R5 as referenced in all the VSLs. Change the "verified according to Requirement" to Requirement R6 versus R5 (all VSLs). Requirement R8 references should be changed to Requirement R9. Just to be clear the Technical Rational should indicate the TO is responsible for the Transmission station(s) and Transmission substation(s) while the TOP is responsible for the Control Center—VSLs language could confuse registered entities.

Requirement R9 should consider "initiated" versus "implemented" as "implemented" and "executed" may be considered synonymous.

R10 VSLs Requirement R7 and R8 references need updated to reflect Requirement language. Change R7 to R8 and R8 to R9 as the evaluation is performed in R8 and the security plan is developed in R9 (all VSLs). Requirement R9.3 reference should change to Requirement R10.3 (all VSLs). Requirement R9.4 reference should be changed to Requirement R10.4 (Severe VSL).

Likes 0	
Dislikes 0	

Response

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper

Answer	
Document Name	

Comment

The Standard or technical rationale document should provide more clarity on the type of physical attack event. This would help determine what type of physical security is needed to prevent/mitigate the risk of the event. More clarification on the type of event would help entities define what type of fault event to use for the risk assessment as well as potential physical security actions if needed should a station or stations be identified in the risk assessment and require additional protection.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators

Answer	
Document Name	

Comment

We would like to thank the SDT for their hard work and allowing us to comment.

Likes 0	
Dislikes 0	

Response