Comment Report

Project Name:	2023-06 CIP-014 Risk Assessment Refinement | Draft 3
Comment Period Start Date:	6/6/2025
Comment Period End Date:	7/21/2025
Associated Ballots:	Project 2023-06 CIP-014 Risk Assessment Refinement CIP-014-4 AB 3 ST Project 2023-06 CIP-014 Risk Assessment Refinement Implementation Plan AB 3 OT

There were 74 sets of responses, including comments from approximately 160 different people from approximately 98 companies representing 8 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the modifications made in CIP-014-4 with modified Requirement R1 to address the issues identified in the SAR? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

2. Do you agree with the modifications made in CIP-014-4 with new Requirement R2 to address the issues identified in the SAR? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

3. Do you agree with the modifications made in CIP-014-4 with new Requirement R3 to address the issues identified in the SAR? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

4. Do you agree with the modifications made in CIP-014-4 with new Requirement R4 to address the issues identified in the SAR? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

5. Do you agree with the modifications made in CIP-014-4 with adding Requirement R5 to address the issues identified in the SAR? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

6. Do you agree with the Implementation Plan for CIP-014-4? If you think an alternate timeframe is needed, please propose an alternate implementation plan with a detailed explanation.

7. Do you believe there are alternatives or more cost-effective options to address the recommendations in CIP-014-4 to address the reliability issue of physical security? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

8. Provide any additional comments for the 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
					George Brown	Pattern Operators LP	5	MRO
					Amy Key	MidAmerican Energy Company (MEC)	1	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Peter Brown	Invenergy	5,6	MRO
					Angela Wheat	Southwestern Power Administration	1	MRO
					Joshua Phillips	Southwest Power Pool	2	MRO
					Patrick Tuttle	Oklahoma Municipal Power Authority	4,5	MRO
					Hayden Maples	Evergy	1,3,5,6	MRO
					Kirsten Rowley	MISO	2	MRO
					Andrew Coffelt	Kansas City Board of Public Utilities	1,3,5,6	MRO

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
					Darren Boehm	Tennessee Valley Authority	5	SERC
					Jeffrey Powell	Tennessee Valley Authority	6	SERC
Santee Cooper	Chris Wagner	1		Santee Cooper	Weijian Cong	Santee Cooper	1,3,5,6	SERC
					John Abrams	Santee Cooper	1,3,5,6	SERC
Exelon	Daniel Gacek	1		Exelon	Daniel Gacek	Exelon	1	RF
					Kinte Whitehead	Exelon	3	RF
Con Ed - Consolidated Edison Co. of New York	Dermot Smyth	1	NPCC	Con Edison	Dermot Smyth	Con Edison Company of New York	1,3,5,6	NPCC
					Edward Bedder	Orange & Rockland		NPCC
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
Black Hills Corporation	Josh Schumacher	6		Black Hills Corporation Segments 1, 3, 5, 6	Trevor Rombough	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC

					Sheila Suurmeier	Black Hills Corporation	5	WECC
					Josh Schumacher	Black Hills Corporation	6	WECC
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
California ISO	Monika Montez	2	WECC	ISO/RTO Council Standards Review Committee (SRC)	Monika Montez	CAISO	2	WECC
					John Pearson	ISO New England, Inc.	2	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Elizabeth Davis	PJM	2	SERC
Northeast Power Coordinating Council	Ruida Shu	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 Edison Co. of New York	1	NPCC
David Burke	Orange and Rockland	3	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
Sean Cavote	PSEG	4	NPCC
Jason Chandler	Con Edison	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
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
					Emma Halilovic	Hydro One	1,3	NPCC
					Philip Nichols	National Grid	1	NPCC
					Emma Halilovic	Hydro One	1,3	NPCC
					Caver Powers	Utility Services	5	NPCC
Public Utility District No. 1 of Chelan County	Tamarra Hardie	6		CHPD	Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Rebecca Zahler	Public Utility District No. 1 of Chelan County	5	WECC
					Diane Landry	Public Utility District No. 1 of Chelan County	1	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 Northern California	1	WECC

1. Do you agree with the modifications made in CIP-014-4 with modified Requirement R1 to address the issues identified in the SAR? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Nikki Carson-Marquis - Nikki Carson-Marquis On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Nikki Carson-Marquis

Answer	No
Document Name	

Comment

MPC continues to strongly disagree with the use of a 36-month timeframe for utilities who have not previously identified stations or substations as applicable. Increasing the study frequency from every 60 months to every 36 months increases the study burden and cost for utilities without applicable Transmission station(s) or substation(s) while providing no documented benefit to reliability of the BES. MPC proposes to retain the every 60 month requirement for entities that have not identified applicable assets, and include Transmission station(s) and Transmission substation(s) planned to be in service within 60 calendar months. Please see MPC's response to Question 5 for more discussion.

Likes 0	
Dislikes 0	

Response

Isidoro Behar - Long Island Power Authority - 1

Answer	No
Document Name	

Comment

Question for the SDT: Considering the Measure 1 verbiage ("evidence may include, but are not limited to, dated written or electronic documentation of the Transmission station(s) and Transmission substation(s) (existing and those planned to be in service within 36 calendar months) that meet any of the criteria in Attachment 1."), what action is needed to demonstrate compliance with respect to "identifying" applicable stations, and what notification(s) is needed? Our observation is that the Req #1 verbiage and the Measure 1 verbiage do not align.

Additionally, we observe that the term "applicable" station is introduced in Req# 1 and is used throughout the standard. The term "proximate" station is introduced in Req #2 and is referred to in Reqs 3.3 and 5. Based on this revision to the standard, these are two distinct sets of stations (applicable and proximate). We observe that for a few requirements / sub-requirements, there may be a possible gap or point of confusion as to whether a proximate station needs to meet the requirement / sub-requirement.

As a general comment, we recommend that the specific use of both of these terms be reviewed in fine detail to ensure no that there will no confusion as to whether a requirement pertains to an applicable station, a proximate station, or to both.

Likes 0	
Dislikes 0	

Response

Steven Belle - Dominion - Dominion Virginia Power - 1	
Answer	No
Document Name	
Comment	
Dominon beleives that 36 months identification requirement for planned substations is unrealistic and difficult to predict based on constructon delays, supply chain, outage planning and RTO planning requirements.	
Likes 0	
Dislikes 0	
Response	

Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	
We do not support the change from 60 months (with no previous applicable substation) to 36 months as there appears to be no technical basis that supports this change. This timeframe causes the Transmission Owner (TO) to enter an unknown state of compliance with CIP-014 if they are on Years 4-5 from the previous 60-month Requirement. The current state of the risk assessment requirements is subjective and TO's should not be forced to perform subjective study efforts on a more frequent basis which only pulls important resources in directions that provide no value to the industry. Further, most significant EHV expansion projects which would actually change the previous base case assumptions do not occur every 36 months and are more in line with 60-month construction periods.	
Likes 1	Nebraska Public Power District, 5, Bender Ronald
Dislikes 0	
Response	

Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
ATC agrees with MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the modifications made in R1	
Likes 0	
Dislikes 0	
Response	
Randy Peters - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Manitoba Hydro agrees with the change that all entities should identify applicable substations every 36 months.	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy agrees with the modifications made to Requirement R1.	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
A three-year calendar cycle is easier to follow.	
Likes 0	
Dislikes 0	
Response	
Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with the modifications made in CIP-014-4 Requirement R1.	
Likes 0	
Dislikes 0	
Response	
Misty Carneal - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	Yes

Document Name	
Comment	
Duke Energy supports the modifications to R1.	
Likes 0	
Dislikes 0	
Response	
Matt Carden - Southern Company - Southern Company Services, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Southern Company agrees with the modifications made in CIP-014-4 Requirement R1.	
Likes 0	
Dislikes 0	
Response	
Timothy Singh - Timothy Singh On Behalf of: Israel Perez, Salt River Project, 3, 6, 5, 1; Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; - Timothy Singh	
Answer	Yes
Document Name	
Comment	
SRP agrees with the consolidation of timelines into a single 36-month cycle in Requirment R1.	
Likes 0	
Dislikes 0	
Response	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	Yes
Document Name	
Comment	

Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
"Please see EEI Comments"	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Nextera agrees with modifications made in CIP-04-4, R1	
Likes 0	
Dislikes 0	
Response	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI agrees with the modifications made in CIP-014-4 Requirement R1.	

Likes 0	
Dislikes 0	

Response

Dan Perry - TXNM Energy - 1,3,5 - WECC,Texas RE

Answer	Yes
Document Name	

Comment

TXNM Energy agrees with modifications made in CIP-014-4 Requirement R1

Likes 0	
Dislikes 0	

Response

Lucinda Bradshaw - Lucinda Bradshaw On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Lucinda Bradshaw

Answer	Yes
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Kelley Sargent - Puget Sound Energy, Inc. - 3

Answer	Yes
Document Name	

Comment

Agree with modification to reduce risk assessment frequency to every 36 months (from current every 30 months) and increase study window for planned substations to 36 months (from current 24 months).

Likes 0	
Dislikes 0	

Response	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
See comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
The ISO/RTO Council (IRC) Standards Review Committee (SRC) agrees that the SAR achieves consistency.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	

Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 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	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tamarra Hardie - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD	
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 0	
Dislikes 0	
Response	
Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 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	
Thomas Breen - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darko Kovac, P.E. - Gainesville Regional Utilities - 1,3,5	
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	
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	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Melanson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Jodi Yeary - AEP - 3

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

Phillip Martinez - Phillip Martinez On Behalf of: Richard Jackson, U.S. Bureau of Reclamation, 1, 5; - U.S. Bureau of Reclamation - 1 - WECC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 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	
Lincoln Burton - Con Ed - Consolidated Edison Co. of New York - 3	
Answer	Yes
Document Name	
Comment	
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	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	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Zahid Qayyum - New York Power Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
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	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 10, Group Name NPCC RSC	
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	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joseph Scott - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wesley Maurer - Lower Colorado River Authority - 1 - Texas RE	
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	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
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	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emma Halilovic - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Lexi Dobrzysnki - Lexi Dobrzysnki On Behalf of: Angela Dockter, Alliant Energy Corporation Services, Inc., 4; - Lexi Dobrzysnki	
Answer	
Document Name	
Comment	
Alliant Energy mirrors the MRO NSRF group Comments.	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with the modifications made in CIP-014-4 with new Requirement R2 to address the issues identified in the SAR? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Emma Halilovic - Hydro One Networks, Inc. - 1	
Answer	No
Document Name	2023-06 Draft_3_Comment_Form.docx
Comment	
See attached for recommendations and rationales.	
Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	No
Document Name	
Comment	
See comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	

Lucinda Bradshaw - Lucinda Bradshaw On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Lucinda Bradshaw	
Answer	No
Document Name	
Comment	

Oncor appreciates that the ambiguous sub-requirements have been removed from Requirement R2, but ambiguity remains in the proposed revised Requirement R2. As a result, Oncor does not fully agree with the modifications made in new Requirement R2.

Oncor's previous comment on revised Requirement R2 requested clarification as to what voltage classes are applicable for proximate Transmission stations and Transmission substations. In the Drafting Team's response, the Drafting Team clarified that proximate Transmission stations and Transmission substations should only be considered if they are part of the Bulk Electric System (operated at 100 kV or higher). At no point is this clarified in the language of the revised Standard. Because the Standard currently only identifies an exclusion for voltages below 200 kV, Oncor recommends CIP-014-4 Requirement R2 be clarified by adding a statement that proximate Transmission stations and Transmission substations only require consideration if they are part of the Bulk Electric System. Oncor proposes that the following sentence be added to the end of the existing proposed revised Requirement 2: "***Transmission Owners only need to identify proximate Transmission station(s) and Transmission substation(s) that are part of the Bulk Electric System.***"

Oncor also previously commented on the burdensome task of coordination with other parties to track Transmission stations and Transmission substations that are owned by other parties to determine if any stations are within the specified distance threshold. The Drafting Team clarified that there is no need to coordinate with another entity; rather, the Transmission Owner (TO) may use "common public access tools" to identify proximate Transmission stations and Transmission substations. While the use of such tools (*e.g.*, GIS data) may alleviate coordination burdens, it introduces new burdens on TOs to manually review each and every applicable Transmission station and Transmission substation for nearby stations. Oncor has three additional concerns that should be noted related to the use of GIS data:

· GIS data for an area can be low resolution, limited, or entirely unavailable.

· Another complication that could arise is that TOs may unknowingly use GIS data that is out-of-date and no longer representative of the subject area. For example, if a TO used the most recent imagery available from Google Earth to perform its review of an area in 2025, and that imagery was created in 2023, then that imagery would not include any nearby Transmission stations that were built in 2024. Then the TO's review performed in 2025 would not include any proximate stations built in 2024.

· Even if a TO uses current year GIS data in an effort to identify proximate Transmission stations and Transmission substations, this still would not allow the TO to identify planned but not completed proximate stations. For example, a TO could use GIS data to identify proximate stations in 2025, but if in 2026 a new proximate station was built, then the proximate station built in 2026 would not be accounted for in the 2025 review.

Likes 0	
Dislikes 0	
Response	
Wesley Maurer - Lower Colorado River Authority - 1 - Texas RE	
Answer	No
Document Name	
Comment	

We do not agree with the changes to R2 as currently written. The use of the term "identify" is unclear, it's not obvious whether this requires documentation or ongoing tracking. There's also no voltage threshold provided, adding a voltage threshold could provide more clarity and keep from including stations that aren't relevant from a security perspective. It is also uncertain what is expected once these substations are identified, particularly if they are owned by another entity.

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 distance of 1500 feet or 457 meters (the shortest distance, measured substation fence line to substation fence line) selected by the drafting team for proximate Transmission station(s) and Transmission substation(s). However, we are concerned Transmission stations and Transmission substations owned by other entities who CIP-014 may or may not be applicable cannot be compelled to provide the information necessary for entities to comply with CIP-014. Further, while GIS tools can identify stations and substations within the specified proximity, it can be difficult to determine whose station they might be and if they are Transmission station(s) or Transmission substation(s)

ITC suggests narrowing the scope to existing BES Transmission station(s) and BES Transmission substation(s) which are owned by the applicable entity.

R2. Each Transmission Owner shall identify proximate **BES** Transmission station(s) and **BES** Transmission substation(s), owned by the applicable TO, within 1500 feet or 457 meters (the shortest distance, measured substation fence line to substation fence line) of an applicable Transmission station or Transmission substation identified in Requirement R1. [Violation Risk Factor: Medium; Time-Horizon: Long-term Planning]

ITC asks the drafting team to consider adding content to the technical rationale describing ways that an entity can be confident of to demonstrate compliance that are not cost prohibitive for companies with facilities in numerous states. Concern is identifying stations not owned by the TO.

Likes 0	
Dislikes 0	
Response	
Joseph Scott - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	

We do not agree with the changes to R2 as currently written. The use of the term “identify” is unclear, it’s not obvious whether this requires documentation or ongoing tracking. There’s also no voltage threshold provided, adding a voltage threshold could provide more clarity and keep from including stations that aren’t relevant from a security perspective. It is also uncertain what is expected once these substations are identified, particularly if they are owned by another entity.

Likes 0	
Dislikes 0	
Response	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI supports the distance of 1500 feet or 457 meters (the shortest distance, measured substation fence line to substation fence line) selected by the drafting team for proximate Transmission station(s) and Transmission substation(s). However, we are concerned Transmission stations and Transmission substations owned by non-registered entities are not compelled to provide the information necessary for entities to comply with CIP-014. Further, while GIS tools can identify stations and substations within the specified proximity, it can be difficult to determine if they are Transmission station(s) or Transmission substation(s).

EEI suggests narrowing the scope to BES Transmission station(s) and BES Transmission substation(s) which are owned by registered entities who would be compelled to share CIP-014 related information.

R2. Each Transmission Owner shall identify proximate **BES** Transmission station(s) and **BES** Transmission substation(s), irrespective of ownership, within 1500 feet or 457 meters (the shortest distance, measured substation fence line to substation fence line) of an applicable Transmission station or Transmission substation identified in Requirement R1. [Violation Risk Factor: Medium; Time-Horizon: Long-term Planning]

EEI asks the drafting team to consider adding content to the technical rationale describing ways that an entity may choose to accurately measure distances and demonstrate compliance. For instance, Google Earth measurements, leveraging internal personnel, hiring a surveying company etc.

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

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

Answer	No
Document Name	

Comment

"Please see EEI Comments"

Likes 0	
Dislikes 0	

Response	
Ruida Shu - Northeast Power Coordinating Council - 10, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	
The use of the word “proximate” appears to imply an estimation and leaves the determination of what constitutes a nearby Transmission Substation or Station to the discretion of the entity. However, the requirement specifies a precise distance and a method for measuring that distance. NPCC RSC recommends removing the word “proximate.” NPCC RSC also recommends modifying Requirement R2 to read: “Transmission station(s) and Transmission substation(s) identified in CIP-002.” If the intent is to conduct a separate process or analysis to identify applicable assets, that assessment should be performed under CIP-002.	
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	
Consider putting back the "line of sight" and "ease of access" language since physical attacks or the likelihood of physical attacks could be evaluated based on how easily accessible (physically) stations are to one another.	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
Answer	No
Document Name	
Comment	

We do not agree with using proximity as the only triggering factor for this requirement. An entity (particularly urban utilities) may have transmission stations within 1,500 feet of each other but due to their design (i.e., Open Air vs. Enclosed) the impact of a possible physical attack can be mitigated. It would be impossible to have simultaneous faults at the applicable and proximate station under those circumstances. An example of a revised R2:

R2: Each Transmission Owner shall identify proximate open-air Transmission station(s) and Transmission substation(s), irrespective of ownership, within 1500 feet or 457 meters (the shortest distance, measured substation fence line to substation fence line) of an applicable Transmission station or Transmission substation identified in Requirement R1

Additionally, the technical rationale does not include the name or a link to the study that was the basis for this modified requirement; knowing what specific reliability concerns this modified requirement was intended to mitigate would be helpful.

Likes 0	
Dislikes 0	

Response

Zahid Qayyum - New York Power Authority - 5

Answer	No
Document Name	

Comment

NYPA supports NPCC RSC comments.

Likes 0	
Dislikes 0	

Response

Jamison Cawley - Nebraska Public Power District - 1

Answer	No
Document Name	

Comment

We disagree with the 1,500 feet requirement as there is no clear definition of the initiating disturbance. The initiating event could be anything from gunshots up to a “smoking crater” scenario and the impacts to adjacent substations could range from minimal or moderate damage to severe damage, all of which are undefined in this standard. The Physical Security standard was proposed to enhance the physical security at critical BES substations, but there are no enhanced physical security defense mechanisms which can protect a substation from a missile attack which is the only feasible way to result in a “Smoking Crater” scenario at multiple substations. So, the attack scenarios need to be plausible so that realistic physical security enhancements can be deployed to facilitate improvements in the security posture at critical BES substations. The “Smoking Crater” scenario is not plausible and thus the 1,500 feet impact zone is not justified. Assuming a simultaneous 3-Phase fault on every element in a large substation along with each and every element of an adjacent substation within 1,500 feet cannot be technically justified and therefore cannot be a requirement for the risk

assessment. Experienced TOs know through prior disturbance analysis events, that 3-phase faults are rare at a single point in the entire transmission system, so they should not be assumed to occur at one exact point in time on multiple elements at multiple substations covering large distances.	
Likes 1	Nebraska Public Power District, 5, Bender Ronald
Dislikes 0	
Response	
Timothy Singh - Timothy Singh On Behalf of: Israel Perez, Salt River Project, 3, 6, 5, 1; Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; - Timothy Singh	
Answer	No
Document Name	
Comment	
SRP recommends establishing clearer criteria for determining station applicability. As currently written, the requirement is open to interpretation, specifically regarding which voltage levels and which stations are included under the phrase " of any applicable Transmission station." To avoid ambiguity, we recommend clarifying section 4 or specifying that Requirement R2 applies only to Transmission stations or Transmission substations identified by the Transmission Owner through the risk assessment process described in Requirement R1, in accordance with the Applicability criteria outlined in Attachment 1.	
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 Institute for question #2.	
Likes 0	
Dislikes 0	
Response	
Lincoln Burton - Con Ed - Consolidated Edison Co. of New York - 3	
Answer	No
Document Name	

Comment	
We do not agree with using proximity as the only triggering factor for this requirement. An entity (particularly urban utilities) may have transmission stations within 1,500 feet of each other but due to their design (i.e., Open Air vs. Enclosed) the impact of a possible physical attack can be mitigated. It would be impossible to have simultaneous faults at the applicable and proximate station under those circumstances. An example of a revised R2: R2: Each Transmission Owner shall identify proximate open-air Transmission station(s) and Transmission substation(s), irrespective of ownership, within 1500 feet or 457 meters (the shortest distance, measured substation fence line to substation fence line) of an applicable Transmission station or Transmission substation identified in Requirement R1 Additionally, the technical rationale does not include the name or a link to the study that was the basis for this modified requirement; knowing what specific reliability concerns this modified requirement was intended to mitigate would be helpful.	
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	
The use of the word "proximate" appears to imply an estimation and leaves the determination of what constitutes a nearby Transmission Substation or Station to the discretion of the entity. However, the requirement specifies a precise distance and a method for measuring that distance. NPCC RSC recommends removing the word "proximate." NPCC RSC also recommends modifying Requirement R2 to read: "Transmission station(s) and Transmission substation(s) identified in CIP-002." If the intent is to conduct a separate process or analysis to identify applicable assets, that assessment should be performed under CIP-002.	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	
Comment	

We do not agree with using proximity as the only triggering factor for this requirement. An entity (particularly urban utilities) may have transmission stations within 1,500 feet of each other but due to their design (i.e., Open Air vs. Enclosed) the impact of a possible physical attack can be mitigated. It would be impossible to have simultaneous faults at the applicable and proximate station under those circumstances.

An example of a revised R2:

R2: Each Transmission Owner shall identify proximate open-air Transmission station(s) and Transmission substation(s), irrespective of ownership, within 1500 feet or 457 meters (the shortest distance, measured substation fence line to substation fence line) of an applicable Transmission station or Transmission substation identified in Requirement R1

Additionally, the technical rationale does not include the name or a link to the study that was the basis for this modified requirement; knowing what specific reliability concerns this modified requirement was intended to mitigate would be helpful.

Likes 0	
Dislikes 0	

Response

Steven Belle - Dominion - Dominion Virginia Power - 1

Answer	No
Document Name	

Comment

Clarification is needed that adjacent stations only refers to BES stations. Additionally, the 1500ft distance is unnecessarily perscriptive and should be provided only as guidance. Each entity's physical security experts, in concert with 3rd party evaluators, should have latitude to determine the apporpriate distance to consider givent the unique characteristics and vulnerabilities of each site under evalution.

Likes 0	
Dislikes 0	

Response

Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison

Answer	No
Document Name	

Comment

We do not agree with using proximity as the only triggering factor for this requirement. An entity (particularly urban utilities) may have transmission stations within 1,500 feet of each other but due to their design (i.e., Open Air vs. Enclosed) the impact of a possible physical attack can be mitigated. It would be impossible to have simultaneous faults at the applicable and proximate station under those circumstances. An example of a revised R2:
R2: Each Transmission Owner shall identify proximate open-air Transmission station(s) and Transmission substation(s), irrespective of ownership,

within 1500 feet or 457 meters (the shortest distance, measured substation fence line to substation fence line) of an applicable Transmission station or Transmission substation identified in Requirement R1
Additionally, the technical rationale does not include the name or a link to the study that was the basis for this modified requirement; knowing what specific reliability concerns this modified requirement was intended to mitigate would be helpful.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Southern Company proposes the language below for added flexibility and recognition of risk mitigations similar to the flexibility proposed in Draft 2 that Southern Company agreed with and voted yes.

R2. Each Transmission Owner shall identify proximate Transmission station(s) and Transmission substation(s), irrespective of ownership

2.1 Transmission station(s) and Transmission substation(s) within 500 feet or 152 meters (the shortest distance, measured substation fence line to substation fence line) of an applicable Transmission station or Transmission substation identified in Requirement R1

or:

2.2 Transmission station(s) and Transmission substation(s) between 500 feet or 152 meters and 1500 feet or 457 meters with line of sight from a single location without obstruction of an applicable Transmission station or Transmission substation identified in Requirement R1

or:

2.3 Transmission station(s) and Transmission substation(s) between 500 feet or 152 meters and 1500 feet or 457 meters with ease of access from a common roadway that exists between an applicable Transmission station or Transmission substation identified in Requirement R1

Likes 0	
Dislikes 0	

Response

Misty Carneal - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy supports EEI comments that suggest further clarifying the scope to BES Transmission station(s) and BES Transmission substation(s) which are owned by registered entities. Duke Energy recommends the following: R2. Each Transmission Owner shall identify proximate **BES** Transmission station(s) and **BES** Transmission substation(s), irrespective of ownership, within 1500 feet or 457 meters (the shortest distance, measured substation fence line to substation fence line) of an applicable Transmission station or Transmission substation identified in Requirement R1. [Violation Risk Factor: Medium; Time-Horizon: Long-term Planning]	
Likes 0	
Dislikes 0	
Response	
Jodi Yeary - AEP - 3	
Answer	No
Document Name	
Comment	
AEP is supportive of the modifications. However, specifying fence line to fence line is too prescriptive. Many utilities already have systems of record for station coordinates/addresses that are currently or can be used for distance calculations that are not based on fence boundaries. This prescriptive boundary language adds unnecessary compliance burden and possibly requires TOs to create and maintain a new system of record. AEP's preference is to leave boundary definitions to the TOs discretion as long as their methodology for distance calculation is documented.	
Likes 0	
Dislikes 0	
Response	
Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with EEI regarding the new requirements in R2. We support the distance of 1500 feet measured between the closest sections of substation fencing. However, we have concerns about non-registered entities not being compelled to provide information necessary for registered entities to comply with CIP-014-4. Black Hills Corporation agrees with EEI's recommendation of adding the 'BES' verbiage to Transmission	

station and Transmission substation to reduce the scope to entities who would be compelled to comply with CIP-014-4. We also agree with the suggestion to add acceptable ways to measure the distance between substations into the technical rationale for clarity.	
Likes 0	
Dislikes 0	
Response	
Isidoro Behar - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	

PSEG Long Island Agrees with the majority of changes provided to R2, including the fence line to fence line criteria, revision to distance (1500ft, and removal of criteria previously in 2.1 and 2.2.

One improvement would be to include language, to prevent ambiguity of responsibility. Suggested change: "***Each Transmission owner with applicable Transmission station(s) and Transmission substation(s) identified in Requirement R1 shall***…..". This language aims to prevent adjacent transmission owners whose facilities do not meet the criteria identified in R1 from speculating about the proximate facilities, and future projects, of adjacent transmission owners. It's reasonable that the TO's facility who meets the criteria under R1 could identify electrical transmission facilities within the 1500ft distance outlined in R2.

Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	No
Document Name	
Comment	

1) PGAE does not agree with the language of "irrespective of ownership". PGAE does not have authority to evaluate other entities facilities and potentially create a document of record that other entities could be held accountable. Also, PGAE does not want a compliance obligation tied to an entity that we have to authority over.

2) Reviewing the bomb threat standoff card, the reference to 1700 feet of standoff appears to be a reference to the mandatory evacuation distance for a 40 foot Semi-Truck trailer filled with 60,000 pounds of explosives. PGAE does not agree that Vehicle-Borne Improvised Explosive Device (VBIED) are a prevalent enough attack vector that private utilities should be required to protect against them. There are far greater immediate threats.

3) "Proximate Station" Screen-1500 ft Fence-to-Fence Criterion (R2) - The new requirement to list any transmission station located within 1500 ft of a candidate facility acknowledges the risk of multi station, single attack scenarios, yet the fixed distance appears arbitrary. To prevent over or under inclusion, especially in dense urban corridors, PGAE recommends that NERC cite the threat analysis that produced the 1500 ft requirement and allow

entities to justify an alternative distance if a quantified risk assessment shows equivalent or better coverage. This added clarity will reduce regional interpretation disputes and avoid unnecessary modelling effort. This requirement also presents substantial implementation challenges related to inter-utility coordination. Assessing the physical security implications of an attack on a neighboring utility's substation, particularly when there is no existing joint ownership or operational agreement, will necessitate new formal data-sharing protocols and coordination mechanisms. This could lead to administrative complexities, delays in risk assessments, and potential disputes over sensitive information sharing. We urge NERC to provide specific guidance or a recommended template for inter-utility agreements to facilitate this critical coordination.

Likes 0	
Dislikes 0	

Response

David Melanson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5

Answer	No
Document Name	

Comment

NB Power supports NPCCs comments:

"The use of the word “proximate” appears to imply an estimation and leaves the determination of what constitutes a nearby Transmission Substation or Station to the discretion of the entity. However, the requirement specifies a precise distance and a method for measuring that distance. NPCC RSC recommends removing the word “proximate.”
NPCC RSC also recommends modifying Requirement R2 to read:
“Transmission station(s) and Transmission substation(s) identified in CIP-002.”
If the intent is to conduct a separate process or analysis to identify applicable assets, that assessment should be performed under CIP-002."

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

FirstEnergy supports EEI Comments which state:

EEI supports the distance of 1500 feet or 457 meters (the shortest distance, measured substation fence line to substation fence line) selected by the drafting team for proximate Transmission station(s) and Transmission substation(s). However, we are concerned Transmission stations and Transmission substations owned by non-registered entities are not compelled to provide the information necessary for entities to comply with CIP-014.

Further, while GIS tools can identify stations and substations within the specified proximity, it can be difficult to determine if they are Transmission station(s) or Transmission substation(s).

EEI suggests narrowing the scope to BES Transmission station(s) and BES Transmission substation(s) which are owned by registered entities who would be compelled to share CIP-014 related information.

R2. Each Transmission Owner shall identify proximate **BES** Transmission station(s) and **BES** Transmission substation(s), irrespective of ownership, within 1500 feet or 457 meters (the shortest distance, measured substation fence line to substation fence line) of an applicable Transmission station or Transmission substation identified in Requirement R1. [Violation Risk Factor: Medium; Time-Horizon: Long-term Planning]

EEI asks the drafting team to consider adding content to the technical rationale describing ways that an entity may choose to accurately measure distances and demonstrate compliance. For instance, Google Earth measurements, leveraging internal personnel, hiring a surveying company etc.

Likes 0	
Dislikes 0	

Response

Randy Peters - Manitoba Hydro - 1,3,5,6 - MRO

Answer	No
Document Name	

Comment

The technical rationale is not clear for defining the hard limit of 1500 feet as the shortest distance between two substations based on the information presented in a reference guide developed to protect people from a bomb threat, as this is not the only possible hazard addressed by CIP-014. After further review Manitoba Hydro believes the previous criteria in draft-2 are very clear and provide some flexibility for TOs to develop their own proximity criteria.

Such guidelines developed by America's Cyber Defense Agency can be referenced as guideline documents by entities when developing their criteria, but it is not recommended to bring those recommendations into a NERC standard as hard limits. If the SDT believed there was a reliability gap or a risk in the CIP-014-4-draft-2 (R2), then the SDT could think about adding another sub-requirement for TOs to develop a documented criteria or include a criteria into the TO's risk assessment methodology .

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

AZPS agrees with comments submitted by EEI on behalf of their members to narrow the scope of proximate Transmission station(s) or Transmission substation(s) to BES Transmission station(s) and Transmission substation(s) which are owned by registered entities. AZPS agrees with EEI comments that it would be appreciated to consider adding more detail to Measurement M2 describing intended evidence that the distance has been accurately measured.

AZPS also agrees with EEI comments that clarification on if a site is identified as part of Requirement R2 and is owned by a different company how that applies to R8-R10.

Likes 0	
Dislikes 0	

Response

Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson

Answer	No
Document Name	

Comment

Consider the addition of the 36 calendar months timeframe to this requirement to avoid confusion around when this should be completed.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Tri-State recommends the following:

R2 should exclude Transmission stations or substations that are below 200 kV from being considered proximate Transmission stations or substations. Without this exception, the requirement 3.3.2 that faults on proximate stations be studied would result in faults on low voltage systems being studied, despite the general intention of CIP-014 to exclude low voltage stations.

R2 should permit an exception for stations or substations that are not electrically close despite physical proximity. Substations may be physically close, but not have any transmission line connecting them, such that they are functionally distant for power flow and transient stability purposes. While the substation may be damaged/removed by the same attack, they would not be impacted by each other’s faults and would be cleared separately. In addition, the “proximate” substation in this circumstance will frequently be owned by another entity, such that entities will have to perform studies on systems that are entirely owned by others.

Likes 0	
Dislikes 0	

Response

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

No, CenterPoint Energy Houston Electric, LLC (CEHE) agrees with comments as submitted by the Edison Electric Institute (EEI).

Likes 0	
Dislikes 0	

Response

Tamarra Hardie - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD

Answer	No
Document Name	

Comment

The rationale for the 1500 feet requirement refers to the DHS-DOJ Bomb Threat Stand-off Card for semi-trailier type threats as justification for including this number in R2. However, the distances on the Stand-off Card are related to the mandated personnel evacuation distances for a variety of bomb threats, not necessarily damage distances for these threats. For instance, it would be recommended to use a number that is based upon historical and/or technical research for damage distance of semi-trailer type bomb threats rather than the guidance for safe personnel evacuation distance when considering which stations may be impacted by a bombing event.

Additionally, the measurement from substation fence line to substation fence line can present some unrealistic distance scenarios for CIP-014 assessments, especially for substations that share a fence line with another substation and are located within 1500 feet of a third station. There are situations under these conditions where equipment distances may far exceed 1500 feet, which is already a distance determined by evacuation mandates and not by technically-supported damage distances. For instance, a substation may have a large fenced area with power equipment positioned within the fence perimeter in such a way that distances may far exceed 1500 feet from the proposed event blast location to adjacent "proximate" facilities but would still need to be assessed based upon the proposed R2 draft 3 language.

It is recommended to modify this language to be less prescriptive with this distance requirement and instead allow utilities to either:

- Use the provided R2 distance, whether that is the current revision's 1500 foot requirement or a distance based upon damage distances (Note: It is preferable the distance number be based upon technically-supported damage distances rather than mandatory evacuation distances, as mentioned above.)

OR

- Allow utilities to select their own distance for identifying proximate stations but require utilities to provide rationale within their CIP-014 methodologies and/or assessments for why they selected a different distance threshold or excluded proximate stations from identification.

It is requested that NERC provide additional guidance or DHS/DOJ/CISA resources for damage distances of various bomb threat types in a similar fashion to the stand-off card for evacuation distances. This would allow R2 to address the intent of the SAR by requiring utilities to assess semi-trailer type bomb threats to their power systems while also provide additional assessment flexibility and avoiding additional compliance assessment burden for unreasonable scenarios.

Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	
The use of the word “Proximate” seem to intend an estimation and is at the discretion of the entity of what is a close Transmission Substation or Station. Then the requirement states a specific distance and a way to measure that distance. TFIST suggest removing the word “Proximate”.	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes

Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
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	
Tacoma Power supports the specific distance of 1500 feet specified in R2. Typically values specified in dual units are listed as “1500 feet (457 meters)” rather than “1500 feet or 457 meters”. If possible, Tacoma Power recommends adjusting the overall structure of R2 to format the distance measurements with meters in parenthesis rather than as an or statement.	
Likes 0	
Dislikes 0	
Response	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
The ISO/RTO Council (IRC) Standards Review Committee (SRC) recommends that the drafting team should account for the fact that the Transmission Owner might be the only entity that has the information needed to determine which Transmission stations or substations are within 1500 feet or 457 meters of an applicable Transmission station or substation under Requirement R2. Consequently, entities performing unaffiliated third-party verifications under Requirement R6 may not be able to verify that a Transmission Owner has properly identified all Transmission stations or Transmission substations within 1500 feet or 457 meters of applicable stations or substations identified under Requirement R1. As a result, these unaffiliated third parties may need to rely on data provided by the TO when no other data is available, which could undermine the usefulness of unaffiliated third-party verifications.	
Likes 0	
Dislikes 0	
Response	

Kelley Sargent - Puget Sound Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Although the requirement for proximity is simplified from past versions, it is missing the possibility of 2 non-applicable stations (ex. each station with 3-230 kV lines) that if considered proximate (within 1500 feet), may together meet the Applicability criteria. Such a station pair would be missed out from CIP-14-4 requirement R2, as stated currently. Is this an acceptable risk to the interconnection?	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
1. Requesting clarification on the proposed capitalized term “Transmission”. This is not defined by NERC. USV suggests utilizing the term BES transmission stations and BES transmission substations. 2. USV suggest removing the term “proximate” as it does not provide clarity to the requirement. The proposed language states a specific distance and the term proximate does not align due to it suggesting an estimate or approximate value.	
Likes 0	
Dislikes 0	
Response	
Dan Perry - TXNM Energy - 1,3,5 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
TXNM Energy agress with EEI comments	
Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Nextera agrees with modifications made in CIP-04-4, R2	
Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Bright line criteria for proximate distance is appreciated, however, consider defining proximate distances in either feet or meters only.	
Likes 0	
Dislikes 0	
Response	

Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
ATC agrees with MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	

Thomas Breen - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
Support the comments from the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
TEPC agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	
MEC supports the comments of the MRO NSRF	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	

Answer	Yes
Document Name	
Comment	
MRO NSRF thanks the DT for providing the bright line criteria for proximate distance, for further reducing that distance to 1500 ft. with U.S. government justification for that distance, and eliminating the problematic line-of-sight and common roadway considerations	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
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

Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers

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

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	

Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Phillip Martinez - Phillip Martinez On Behalf of: Richard Jackson, U.S. Bureau of Reclamation, 1, 5; - U.S. Bureau of Reclamation - 1 - WECC	
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

Nikki Carson-Marquis - Nikki Carson-Marquis On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Nikki Carson-Marquis

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

Darko Kovac, P.E. - Gainesville Regional Utilities - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
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	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lexi Dobrzysnki - Lexi Dobrzysnki On Behalf of: Angela Dockter, Alliant Energy Corporation Services, Inc., 4; - Lexi Dobrzysnki	
Answer	
Document Name	
Comment	
Alliant Energy mirrors the MRO NSRF group Comments.	
Likes 0	
Dislikes 0	
Response	

3. Do you agree with the modifications made in CIP-014-4 with new Requirement R3 to address the issues identified in the SAR? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	No
Document Name	
Comment	
Steady-State analysis needs to be performed only for on-peak conditions.	
Likes 0	
Dislikes 0	
Response	

Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Idaho Power Company (IPC) recommends the Standard not prescribe a specific second case as a low-load scenario. Instead, IPC suggests the Standard require the second case reflect the system's worst-case conditions outside of the stresses applied in the System peak load case. This case could include scenarios that impose additional or independent stress on the system, such as varying seasonal conditions, path transfers, or different load levels. The specific nature of this case would depend on the system's topology, and system operators would be best positioned to determine what additional stresses should be considered. Additionally, IPC seeks further clarification regarding the term "proximate station" in the context of the requirement: "Faults at both the applicable and proximate Transmission station(s) or Transmission substation(s)." Specifically, IPC requests clarification on whether this requirement implies faults should be evaluated simultaneously across all proximate stations, or if each proximate station should be assessed individually in the same manner as the applicable station.	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
We believe that the loss of applicable transmission stations should extend to transmission substations identified in R2, where they may result in the physical loss of transmission substations in R1. If the association is intended by the Drafting Team, it is not apparent in how R3 is currently written.	

Likes 0	
Dislikes 0	

Response

Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

Requirement 3 creates confusion in situations where two or more substations in close proximity have different owners or joint ownership. It is unclear which entity should apply a fault, especially if the owner identified it under R1 and another entity identified it as proximate. It should be sufficient to apply a fault at the entity's own applicable substation and then take the outage of both the applicable and proximate substations. There would be no need for duplicate fault studies, yet notifications to other entities are not required until R7 is reached.

BPA believes Transmission Owners would have difficulties obtaining and validating information required for proximate Transmission stations or substations. BPA recommends adding language to facilitate coordination among varying entities to ensure data can be received and validated.

R3.4 contains a reference to Part 3.3.2, but there is no such Part in the current redlines. This seems to result in the omission of proximate substations from R3.4, and it is unclear if this is an intentional omission.

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

Developing steady-state and dynamic simulation criteria is a planning function and should not be required of a Transmission Owner. The sub-requirements go further into addressing what a transmission planning study should include but applies this requirement incorrectly to the Transmission owner. The intent of R3 is more appropriately applicable to the TPL body of standards. CIP-014 should reference output from a study performed in accordance with a clearly defined TPL requirement for an extreme event involving the loss of an applicable Transmission station(s) or substation(s).

Likes 0	
Dislikes 0	

Response

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1

Answer	No
Document Name	
Comment	
TEPC agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	No
Document Name	
Comment	
3.1 - The second sentence of R3.1 appears to be deficient. There is no reasonable requirement for the thresholds (e.g., technical justifications). Further, consideration of the thresholds should only be one piece of the analysis, not all of it. R3.3.1 should also take into consideration the stability of the system before the thresholds are met. 3.4 - Consider clear indication of what kind of fault needs to be applied, i.e., a three phase to ground bolted fault or a single line to ground fault. 3.4.2 and 3.4.3 - Consider updating language that actual or more conservative clearing times shall be used and if not available, delayed (remote) clearing times are acceptable.	
Likes 0	
Dislikes 0	
Response	

Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
AZPS agrees with comments submitted by EEI on behalf of their members that there are concerns with the requirement to specify thresholds identifying unacceptable generation and load loss within an Interconnection in Requirement R3 Part 3.1 and their recommendation to remove that language.	
Likes 0	
Dislikes 0	
Response	
Randy Peters - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
It's unclear whether the generation or load loss criteria will simply have specific MW thresholds for generation loss and load loss in the overall interconnected system, or define generation and load loss thresholds both inside and outside of a Planning Coordinator area (but within the overall Interconnection). Consideration could be given to adding a net loss criterion in cases where both generation and load are lost. When the loss of generation and load are of the same order there are typically minimal impacts on the Interconnection	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	No
Document Name	
Comment	
1) Quantifying "Unacceptable Loss" and "Conservative Clearing Time" (R3.1 &R3.4) - The phrases "unacceptable generation and load loss" in R3.1 and "actual or more conservative clearing time" in R3.4 are inherently subjective and open to regional interpretations. To promote uniform implementation, PGAE recommends that NERC establish quantitative default benchmarks for generation and load loss thresholds, and a clearing time margin. Including	

such reference values—while still allowing entities to justify alternative criteria based on system characteristics—will align CIP-014-4 with the measurable approach used in the NERC TPL standards and reduce the potential for inconsistent compliance findings across regions.

2) Clarification on R3.4- Assumption of Total Loss of Communication and Protection Systems – PGAE recommends clarifying the required assumptions for the simultaneous loss of "all communication and protection systems" in R3.4. Defining the expected modelling approach, preferably with an example one line and timing table, will allow entities to build studies that are both realistic and comparable, avoiding unnecessary burden while meeting the standard's risk reduction objectives

Likes 0	
Dislikes 0	
Response	

Isidoro Behar - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	

Req 3.4 – This requirement states:

"*A specification that Fault simulations assume the loss of communication and Protection Systems at the applicable Transmission station(s) or Transmission substation(s) prior to or simultaneous with the Fault(s) studied under Requirement R3, Parts 3.3.1 and 3.3.2."*

It is not clear if the loss of communications and Protection Systems would apply to the proximate station (and thus an affected entity would have to make an assumption). We request clarification that the loss of communications and Protection Systems only applies to the **applicable stations** identified based on Req #1 (and not to the proximate stations identified based on Req #2).

Question for clarification: If the loss of communications and Protection Systems does NOT apply to the proximate stations identified based on Req #2, then is it permissible to assume local high speed protection system clearing times for the fault **at the proximate station?**

Likes 0	
Dislikes 0	
Response	

Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	No
Document Name	
Comment	

Black Hills Corporation agrees with EEI's comments about seeking clarification around the use of numbering vs bullet points in Requirement R3 Part 3.3 and Part 3.4. Generally, bullet points can be considered "OR" requirement and numbered items are treated as "AND" requirements. There are also references to numbered items that don't exist in the current clean version of the document, for example Part 3.4 references Requirement R3 Parts 3.3.1 and 3.3.2, which do not exist in this version of the draft.

Additionally, we agree with EEI's concerns about Requirements R3 Part 3.1 and how it might create scenarios where entities must rely on another party to provide the information necessary to establish and maintain the unacceptable thresholds for generation and load loss within an Interconnection. We agree with EEI's comments to remove some language from requirement R3 Part 3.1 and include it in the technical rationale on how to establish and maintain thresholds.

Likes 0	
Dislikes 0	

Response

Jodi Yeary - AEP - 3

Answer	No
Document Name	

Comment

AEP is supportive of specifying that more than one scenario shall be studied but would like flexibility in choosing what factors are varied between scenarios.

Also the draft currently mixes subrequirements with bullets which should be corrected:

In the clean version of CIP-014-4 that is posted, there are bullet points under Requirement R3 Part 3.3 and 3.4, but Part 3.4 references Requirement R3 Parts 3.3.1 and 3.3.2, which do not exist in this draft. The Redline to Last Posted document includes a Requirement R3 Part 3.3.1 followed by a bullet point, but no Part 3.3.2. The Redline to Last Posted version also includes Requirement R4 Parts 3.4.1-3.4.3 instead of the bullet points that are in the clean version under 3.4.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

R3.2: TVA suggests reverting back to the prior draft of this language that is less prescriptive for what cases are more likely to contribute to instability, uncontrolled separation, or Cascading within an Interconnection.

TVA proposes revise R3.2 as follows: "Steady-state and dynamic simulations shall each be performed using:

(1) A peak-season and an off-peak season, or,

(2) Two different peak-seasons (e.g., summer and winter peak)"	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
SERC appreciates the ongoing efforts to refine the CIP-014 Risk Assessment portion of the standard. SERC believes that each Interconnection Planning Collaborative should establish the maximum generation and load loss thresholds for its respective Interconnection. Allowing each Transmission Owner to establish their own thresholds creates inconsistency for identifying which events cause instability, uncontrolled separation, or Cascading within an Interconnection. SERC believes that the use of the single word 'Fault', does not provide clarity and consistency in the requirement. The fault type should be stated as a 3-phase Fault to align with how Extreme events are studied in TPL-001-5.1.	
Likes 0	
Dislikes 0	
Response	
Steven Belle - Dominion - Dominion Virginia Power - 1	
Answer	No
Document Name	
Comment	
Dominion supports EEI's comments.	
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 Institute and MRO NSRF for question #3.	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	No
Document Name	
Comment	
For R3.3, the use of the term "Fault" opens the door to the usage of less severe faults. We recommend changing "Fault" to "a Fault that will cause the most severe consequences at that substation" to ensure the most serious scenario is studied. The Standard need not specify what fault is to be used in the study, but the Entity would identify what the most serious Fault is and study that.	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	
There appears to be no technical basis to support the inclusion of prior outage scenarios involving communication systems and the ability to assume simultaneous loss of the comm system with the disturbance is also an option here which introduces subjectivity to the process. Including prior outage scenarios in the Risk Assessment (RA) could include prior outages of generators, lines, transformers and other substation equipment which adds further ambiguity to the RA process. The requirement to use delayed clearing times cannot be technically justified for certain protection schemes (DCUB) and the TO should have the ability to use their extensive experience in this area versus a requirement to assume delayed clearing times.	
Likes 1	Nebraska Public Power District, 5, Bender Ronald
Dislikes 0	
Response	

Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	No
Document Name	
Comment	
Ameren would like more clarity around R3.3.1 and the bulleted item beneath it. As written, it is not clear whether both items are required or if there is a choice of which item to complete. Requiring peak and off-peak cases will double the number of simulations that need to be performed.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
"Please see EEI Comments"	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
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. This could result in a scenario where costly additional security measures are shifted to the entity and its customers for an event that crossed the MW threshold but did not cause instability or Cascading in the assessment.	
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

Richard Vendetti - NextEra Energy - 5

Answer	No
Document Name	

Comment

Nextera supports comments submitted by EEI:

EEI appreciates the drafting team's revisions to Requirement R3, however, Requirement R3, Part 3.1 still includes load loss and generation loss which is not required by the SAR.

EEI proposes the following language: "Technically supported thresholds **methodology** and rationale for determining the amount of acceptable load loss, the amount of acceptable generation loss, post event response, and any additional considerations recognized as resulting in instability, uncontrolled separation, or Cascading within an interconnection **used in the analysis to identify System instability for conditions including Cascading, voltage instability, or uncontrolled islanding**. The technical rationale shall include:"

Further, Nextera proposes an addition in R3:

Perform CIP-014 assessment on both individual and group of Transmission station and substation that are in the proximity. Identify whether individual or Proximity Transmission station and Transmission substation are not meeting the Risk Assessment methodology documented in R3.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment
EEI seeks clarification on the drafting team's intention for Requirement R3 Part 3.3 and Part 3.4 sub-requirements. In the clean version of CIP-014-4 that is posted, there are bullet points under Requirement R3 Part 3.3 and 3.4, but Part 3.4 references Requirement R3 Parts 3.3.1 and 3.3.2 which do not exist in this draft. The Redline to Last Posted document includes a Requirement R3 Part 3.3.1 followed by a bullet point, but no Part 3.3.2. The Redline to Last Posted version also includes Requirement R4 Parts 3.4.1-3.4.3 instead of the bullet points that are in the clean version under 3.4. The numbers vs. bullets are important to understand because generally, numbered items are treated as "and" requirements, and bulleted lists can be interpreted as "or" requirements. Additionally, EEI is concerned about the requirement to specify thresholds identifying unacceptable generation and load loss within an Interconnection in Requirement R3 Part 3.1. In some scenarios entities rely on another party to provide the information necessary to establish and maintain these thresholds. EEI suggests striking the sentence "The criteria shall include, at a minimum, thresholds identifying unacceptable generation and load loss within an Interconnection" from Requirement R3 Part 3.1 and including it in the technical rationale with details on how to establish and maintain the thresholds.

Likes 0	
Dislikes 0	

Response

Joseph Scott - Lower Colorado River Authority - 5	
Answer	No
Document Name	

Comment
We do not agree with the changes to R3 as currently written. If a proximate substation falls outside our footprint , we may not have access to the necessary data to perform a proper risk assessment or to evaluate simulation results. It may be more appropriate for this type of assessment to be handled at the regional level.

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 seeks clarification on the drafting team's intention for Requirement R3 Part 3.3 and Part 3.4 sub-requirements. In the clean version of CIP-014-4 that is posted, there are bullet points under Requirement R3 Part 3.3 and 3.4, but Part 3.4 references Requirement R3 Parts 3.3.1 and 3.3.2 which do not exist in this draft. The Redline to Last Posted document includes a Requirement R3 Part 3.3.1 followed by a bullet point, but no Part 3.3.2. The Redline to Last Posted version also includes Requirement R4 Parts 3.4.1-3.4.3 instead of the bullet points that are in the clean version under 3.4. The numbers vs. bullets are important to understand because generally, numbered items are treated as "and" requirements, and bulleted lists can be interpreted as "or" requirements.

Likes 0	
Dislikes 0	

Response

Wesley Maurer - Lower Colorado River Authority - 1 - Texas RE

Answer	No
Document Name	

Comment

We do not agree with the changes to R3 as currently written. If a proximate substation falls outside our footprint , we may not have access to the necessary data to perform a proper risk assessment or to evaluate simulation results. It may be more appropriate for this type of assessment to be handled at the regional level.

Likes 0	
Dislikes 0	

Response

Dan Perry - TXNM Energy - 1,3,5 - WECC,Texas RE

Answer	No
Document Name	

Comment

TXNM Energy agrees with EEI comments and adds the following:

Requirement to run faults at multiple substations is challenging from a software (GE PSLF) perspective and the technical rationale for performing faults at multiple elements does not seem to have basis. Drafting Team should include more information for how this should be accomplished in the Technical Rationale.

Likes 0	
Dislikes 0	

Response

Kelley Sargent - Puget Sound Energy, Inc. - 3	
Answer	No
Document Name	
Comment	

3.1 Thresholds for Unacceptable load or generation loss within an interconnection: It will be helpful if WECC provides thresholds for unacceptable load loss and generation loss that may impact the interconnection. Lack of specific criteria from WECC will lead to inconsistency in CIP-14 assessment methodology among members.

3.3 It will be helpful if standard can clarify if the fault is 3 Phase or single phase.

3.4.2 & 3.4.3 Clearing times: It is not clear if Delayed (remote) clearing times or Actual (more conservative) clearing times shall be used. Does the standard allow both? The technical rationale document for CIP 14-4 (pg. 4) seems to indicate that actual or more conservative clearing times are required. If so, 3.4.2 should be removed.

Likes 0	
Dislikes 0	
Response	

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	No
Document Name	
Comment	

PJM requests language indicating all voltage levels be included in R3 or R3 subrequirements (where the Drafting Team finds the best fit).

Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	No
Document Name	
Comment	

See comments submitted by Edison Electric Institute.

Likes 0	

Dislikes 0	

Response

Emma Halilovic - Hydro One Networks, Inc. - 1	
Answer	No
Document Name	2023-06 Draft_3_Comment_Form.docx

Comment
See attached for recommendations and rationales.

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 is concerned with using bullets for the sub-items in R3.3. Instead of using bullets, these sub-items should be numbered as 3.3.1 and 3.3.2 to ensure that both are required. Bullets are used to indicate an "or" relationship. Additionally, the language in the lead-in statement of R3 should be revised to include proximate stations and substations to ensure it's clear that both should be considered.

Proposed revision to R3:

"R3. Each Transmission Owner shall have a documented risk assessment methodology for evaluating the loss of each applicable Transmission station or Transmission substation identified in Requirement R1, **and any associated proximate Transmissions stations or Transmission substations identified in Requirement R2**. The methodology shall include, at a minimum, the following:

3.3. A specification for Fault simulations, including:

3.3.1. For each applicable Transmission station or Transmission substation listed in accordance with Requirement R1, a Fault at the applicable Transmission station or Transmission substation.

3.3.2. For each Transmission station or Transmission substation determined in accordance with Requirement R2 as being in proximity to an applicable Transmission station or Transmission substation, Faults at both the applicable and proximate Transmission station(s) or Transmission substation(s)."

Tacoma Power recommends swapping the order of R3 and R4. The Requirement R4 actions should occur prior to documenting the methodology.

Also, there's an inconsistency between the CIP-014-4 clean version and redline files. The redline to last approved file shows 3.3.1 and 3.3.2 instead of bullets. The redline to last posted file shows 3.3.1 and a bullet. The clean version has only bullets under R3.3.

Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
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	
MRO NSRF recommends reinstating the option to use more conservative estimates vs. actual clearing times in the last bullet of R3.4. If an Entity wishes to use conservative estimates of clearing times rather than calculate every actual clearing time, an auditor can sample and ask for justification. If the actual clearing time is found to be longer than the estimate the auditor would ask for the study to be re-run with the actual clearing time, which may or may not change whether a Transmission station or substation is identified. Registered Entities should have the latitude to use engineering judgement where they think it is warranted. More importantly, if a conservative estimate of clearing times results in the study identifying a Transmission station or substation, there is no need to re-run the study with actual clearing times. This could save system protection personnel significant time and effort calculating unneeded actual clearing times	
Likes 0	
Dislikes 0	
Response	
Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	

MEC supports the comments of the MRO NSRF
Likes 0
Dislikes 0
Response
Thomas Breen - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1
Answer Yes
Document Name
Comment
Support the comments of the MRO NSRF.
Likes 0
Dislikes 0
Response
Amy Wilke - American Transmission Company, LLC - 1
Answer Yes
Document Name
Comment
ATC agrees with MRO NSRF comments.
Likes 0
Dislikes 0
Response
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter
Answer Yes
Document Name
Comment
FirstEnergy agrees with the modifications made to Requirement R3

Likes 0	
Dislikes 0	
Response	
Misty Carneal - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	Yes
Document Name	
Comment	
Duke Energy agrees with the modifications to R3.	
Likes 0	
Dislikes 0	
Response	
Matt Carden - Southern Company - Southern Company Services, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Southern Company agrees with the modifications made in CIP-014-4 Requirement R3. For clarity, we recommend the language in the second bullet point for Requirement R3.4 to state "**either** prior to or simultaneous with the Fault(s)…"	
Likes 0	
Dislikes 0	
Response	
Timothy Singh - Timothy Singh On Behalf of: Israel Perez, Salt River Project, 3, 6, 5, 1; Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; - Timothy Singh	
Answer	Yes
Document Name	
Comment	
SRP agrees with Requirment R3 by introducing a structured methodology for risk assessment.	
Likes 0	

Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	Yes
Document Name	

Comment

There is a typo in Requirement R3 bullet points being used in R3.4 rather than R3.3.1 and R3.3.2 (redline and clean versions look different.

Also, recommend reinstating the option to use more conservative estimates vs. actual clearing times in the last bullet of R3.4. If an Entity wishes to use conservative estimates of clearing times rather than calculate every actual clearing time, an auditor can sample and ask for justification. If the actual clearing time is found to be longer than the estimate the auditor would ask for the study to be re-run with the actual clearing time, which may or may not change whether a Transmission station or substation is identified. Registered Entities should have the latitude to use engineering judgement where they think it is warranted. More importantly, if a conservative estimate of clearing times results in the study identifying a Transmission station or substation, there is no need to re-run the study with actual clearing times. This could save system protection personnel significant time and effort calculating unneeded actual clearing times.

Likes 0	
Dislikes 0	

Response

Carver Powers - Utility Services, Inc. - 4

Answer	Yes
Document Name	

Comment

Was the intent to have the responsible entity establish their own “unacceptable load loss”? In other cases, it is up to the BA, RC, or RP to determine the Facility’s unacceptable load loss.

Likes 0	
Dislikes 0	

Response

Lucinda Bradshaw - Lucinda Bradshaw On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Lucinda Bradshaw

Answer	Yes
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC)

Answer	Yes
Document Name	

Comment

The ISO/RTO Council (IRC) Standards Review Committee (SRC) agrees that the SAR provides clarity.

Likes 0	
Dislikes 0	

Response

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2

Answer	Yes
Document Name	

Comment

ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1, Group Name Exelon

Answer	Yes
Document Name	

Comment

While Exelon agrees the modifications in the new Requirement R3 address the issues identified in the SAR, we do suggest the following enhancements.

The sub-requirement R3.1 minimum requirement for thresholds identifying unacceptable generation and load loss within an Interconnection would benefit from additional clarification and guidance. For example, perhaps data regarding frequency response to loss of generation and loss of load could act as guidance for entities to establish these thresholds.

To reduce the burden on smaller TOs of developing an R3 methodology and performing the R5 planning studies, consider providing an option for entities to use the list of transmission stations or substations obtained from the Attachment 1 analysis, as the input to R7 for primary control center determination, and as the input to R8 to begin the physical attack evaluation. Attachment 1 would therefore be an option as the R3 methodology that would then be applied in R5. R4 would still be required. The R6 third party review would be limited to a review of the Attachment 1 analysis.

Likes 0	
Dislikes 0	

Response

Jeffrey Streifling - NB Power Corporation - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Tamarra Hardie - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

James Keele - Entergy - 3

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Darko Kovac, P.E. - Gainesville Regional Utilities - 1,3,5

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

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

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
David Melanson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nikki Carson-Marquis - Nikki Carson-Marquis On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Nikki Carson-Marquis	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Phillip Martinez - Phillip Martinez On Behalf of: Richard Jackson, U.S. Bureau of Reclamation, 1, 5; - U.S. Bureau of Reclamation - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 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	
Lincoln Burton - Con Ed - Consolidated Edison Co. of New York - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Zahid Qayyum - New York Power Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
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	
Ruida Shu - Northeast Power Coordinating Council - 10, Group Name NPCC RSC	
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	
Lexi Dobrzysnki - Lexi Dobrzysnki On Behalf of: Angela Dockter, Alliant Energy Corporation Services, Inc., 4; - Lexi Dobrzysnki	
Answer	
Document Name	
Comment	
Alliant Energy mirrors the MRO NSRF group Comments.	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE is still concerned the proposed Requirement Part 3.3 language does not specify the type of fault conditions (line-to-ground fault or three-phase fault) criteria that needs to be studied. If the language will not be added to the requirement, Texas RE requests the Technical Rationale specify whether single-line-to-ground faults or three-phase-to-ground faults are to be included in the simulations, to ensure consistency and clarity in fault analysis across entities.	
Likes 0	
Dislikes 0	
Response	

4. Do you agree with the modifications made in CIP-014-4 with new Requirement R4 to address the issues identified in the SAR? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Robert Blackney - Edison International - Southern California Edison Company - 1

Answer	No
Document Name	

Comment

See comments submitted by Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

Lucinda Bradshaw - Lucinda Bradshaw On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Lucinda Bradshaw

Answer	No
Document Name	

Comment

Oncor appreciates the SDT's response to Oncor's previous comment in the last draft, which affirmed that each TO may prepare its own risk assessment of the subject station and may use its own methodology. Oncor also appreciates the SDT's clarification that, in the event agreement cannot be reached, each TO is able to justify its results using its own supporting evidence.

To ensure this intent of the SDT is clearly conveyed, Oncor believes it would be beneficial to include this clarification directly in Requirement R4 language. Accordingly, Oncor recommends the following addition to Requirement R4:

Each Transmission Owner with applicable Transmission station(s) and Transmission substations(s) identified in Requirement R1 containing Bulk Electric System (BES) Elements owned by multiple Transmission Owners shall coordinate with each appropriate Transmission Owner(s) to determine and document their individual and joint responsibilities for documenting a risk assessment methodology under Requirement R3 and for performing any required risk assessments per Requirement R5. ***In the event that coordination of individual and joint responsibilities cannot be achieved for documenting a risk assessment methodology under Requirement R3 and for performing any required risk assessments per Requirement R5, each Transmission Owner shall document and justify its own risk assessment using its own methodology and evidence.***

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 suggests either the removal of or the following revision to Requirement R4: R4. Each Transmission Owner with applicable Transmission station(s) and Transmission substation(s) identified in Requirement R1 containing Bulk Electric System (BES) Elements **greater than 200 kV or identified as part of an IROL or essential to meeting an NPIR** owned by multiple Transmission Owners shall coordinate with each appropriate Transmission Owner(s) to determine and document their individual and joint responsibilities for documenting a risk assessment methodology under Requirement R3 and for performing any required risk assessments per Requirement R5. R4 is administrative requiring documentation for all joint stations. Many joint stations have existed for decades where the two entities have an understanding of who is responsible for what parts of compliance. When documentation is being required, many entities legal groups will feel a need to be involved making this both time consuming and costly.	
Likes 0	
Dislikes 0	
Response	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI suggests the following revision to Requirement R4: R4. Each Transmission Owner with applicable Transmission station(s) and Transmission substation(s) identified in Requirement R1 containing Bulk Electric System (BES) Elements **greater than 200 kV or identified as part of an IROL or essential to meeting an NPIR** owned by multiple Transmission Owners shall coordinate with each appropriate Transmission Owner(s) to determine and document their individual and joint responsibilities for documenting a risk assessment methodology under Requirement R3 and for performing any required risk assessments per Requirement R5. EEI also asks the drafting team to consider adding content to the Technical Rationale describing how an entity can prove that they do not have anyone to coordinate with because there are no jointly owned Transmission station(s) or Transmission substation(s).	
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

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

Answer	No
Document Name	

Comment

"Please see EEI Comments"

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 10, Group Name NPCC RSC

Answer	No
Document Name	

Comment

Based on the Technical Rationale, the inclusion of “BES Elements” appears to reference the addition of jointly owned Transmission stations and Transmission substations in the Applicability section. However, introducing the term “BES Elements” creates confusion by shifting the focus to individual elements rather than the applicable Transmission stations and substations.

Likes 0	
Dislikes 0	

Response

Zahid Qayyum - New York Power Authority - 5

Answer	No
Document Name	

Comment

NYPA supports NPCC RSC comments.

Likes 0	

Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	
The CIP-014 RA should be limited to the substation equipment that the TO owns. There are different study assumptions and criteria available to different TOs and to attempt to coordinate this on this new 36-month timeframe will only require further resources from multiple TOs who may not be willing to share CEII information in an open forum.	
Likes 1	Nebraska Public Power District, 5, Bender Ronald
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 Institute and MRO NSRF for question #4.	
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	
Based on the Technical Rationale, the inclusion of “BES Elements” appears to reference the addition of jointly owned Transmission stations and Transmission substations in the Applicability section. However, introducing the term “BES Elements” creates confusion by shifting the focus to individual elements rather than the applicable Transmission stations and substations.	
Likes 0	

Dislikes 0	

Response

Steven Belle - Dominion - Dominion Virginia Power - 1

Answer	No
Document Name	

Comment

Dominion supports EEI's comments.

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 supports coordination among joint owners as an important goal. However, the proposed language essentially introduces a major coordination burden, and it assumes a level of entity collaboration, timing, and methodological alignment. It also raises a compliance risk for one entity being dependent on the responsiveness and practices of another.

TVA suggests modifying the draft language to provide flexibility and protects compliant TOs from being penalized for other's inaction(s), as follows:

"Each Transmission Owner with applicable Transmission station(s) and Transmission substation(s) identified in Requirement R1 containing Bulk Electric System (BES) Elements owned by multiple Transmission Owners shall coordinate with those each appropriate Transmission Owner(s) to determine and document their individual responsibilities for documenting a risk assessment methodology under Requirement R3 and for performing any required risk assessments per Requirement R5."

Or…

"Each Transmission Owner with applicable Transmission station(s) and Transmission substation(s) identified in Requirement R1 containing Bulk Electric System (BES) Elements owned by multiple Transmission Owners shall coordinate with those each appropriate Transmission Owner(s) to determine and document their individual responsibilities for documenting a risk assessment methodology under Requirement R3 and for performing any required risk assessments per Requirement R5. In cases where agreement is not achieved, each Transmission Owner shall independently assess and document its own responsibilities and the basis for any assumptions regarding joint ownership impacts."

Likes 0	
Dislikes 0	

Response

Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	No
Document Name	
Comment	

Black Hills Corporation agrees with EEI's suggested revision to the language in Requirement R4. We also agree with adding content to the Technical Rationale describing how an entity can prove they do not have any jointly owned Transmission stations or substations that require coordinating with another party.

Likes 0	
Dislikes 0	
Response	

Isidoro Behar - Long Island Power Authority - 1	
Answer	No
Document Name	
Comment	

As a general comment, Req# 4 needs to be reviewed in detail to ensure clarity and to ensure clear compliance responsibilities.

Req #4 states:

"Each Transmission Owner with applicable Transmission station(s) and Transmission substation(s) identified in Requirement R1 containing Bulk Electric System (BES) Elements owned by multiple Transmission Owners shall coordinate with each appropriate Transmission Owner(s) to determine and document their individual and joint responsibilities for documenting a risk assessment methodology under Requirement R3 and for performing any required risk assessments per Requirement R5."

Req #4 now requires a Transmission Owner to DOCUMENT which TO is responsible for DOCUMENTING specific portions of the risk assessment methodology (RAM). In the previous version of the standard, it only asked TOs to document who is responsible for PERFORMING the risk assessment methodology, but now it must be explicitly outlined who is responsible for even DOCUMENTING parts of that RAM. We would like to point this out so that the SDT can verify if "documenting" individual and joint responsibilities for "documenting" a risk assessment methodology is part of the intent of this revised requirement.

Based on the Technical Rationale, the inclusion of "BES Elements" appears to reference the addition of jointly owned Transmission stations and Transmission substations in the Applicability section. However, introducing the term "BES Elements" creates confusion by shifting the focus to individual elements rather than the applicable Transmission stations and substations.

Req #4 specifically addresses facilities (BES Elements) with joint ownership to coordinate/collaborate. One improvement would be to include Transmission Owners whose stations have been identified as part of Req #2 to also be included in this requirement to coordinate. The ownership of the applicable and proximate stations may be different, and thus we feel the concept of coordination with respect to Req #2 should apply.

We note that there are various possibilities with respect to ownership and to what stations may be considered applicable versus proximate. It is noted that an applicable station owned by one TO may also be considered a proximate station from the perspective of another TO that owns an adjacent applicable station (and vice versa; a proximate station from the perspective of a TO may also be considered an applicable station by another TO).

Likes 0	

Dislikes 0	
Response	
David Melanson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	No
Document Name	
Comment	
NB Power supports NPCCs comments: "Based on the Technical Rationale, the addition of “BES Elements” points to the addition of “jointly owned” Transmission stations and Transmission substations in the Applicability section. However, the introduction of the term(s) “BES Elements” adds confusion by speaking to Elements instead of the applicable Transmission stations and Transmission substations."	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy supports EEI comments which state: R4. Each Transmission Owner with applicable Transmission station(s) and Transmission substation(s) identified in Requirement R1 containing Bulk Electric System (BES) Elements **greater than 200 kV or identified as part of an IROL or essential to meeting an NPIR** owned by multiple Transmission Owners shall coordinate with each appropriate Transmission Owner(s) to determine and document their individual and joint responsibilities for documenting a risk assessment methodology under Requirement R3 and for performing any required risk assessments per Requirement R5. EEI also asks the drafting team to consider adding content to the Technical Rationale describing how an entity can prove that they do not have anyone to coordinate with because there are no jointly owned Transmission station(s) or Transmission substation(s).	
Likes 0	
Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No

Document Name	
Comment	
CEHE agrees with 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 requirement is appropriate in the context that the referenced risk assessment is from a physical security perspective and not a transmission planning analysis perspective. Should the intent of this comment be applicable to physical security and not a transmission planning analysis, then our answer would be yes.	
Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes it would be more thorough to include R2-identified proximate substations in the language of R4, because proximate substations could be jointly owned and require the same coordination of roles and responsibilities for including them in R3 and R5 activities.	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	

Comment	
Based on the Technical Rationale, the addition of “BES Elements” points to the addition of “jointly owned” Transmission stations and Transmission substations in the Applicability section. However, the introduction of the term(s) “BES Elements” adds confusion by speaking to Elements instead of the applicable Transmission stations and Transmission substations.	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	

The ISO/RTO Council (IRC) Standards Review Committee (SRC) agrees that the SAR provides clarity.

Likes 0	
Dislikes 0	

Response

Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers

Answer	Yes
Document Name	

Comment

This requirement does not apply to Ameren.

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	Yes
Document Name	

Comment

An auditor may asks a Registered Entity to produce evidence proving a negative, i.e. that one or more subs are solely owned. M4 discusses how to show evidence that coordination with joint owners has been completed, but it would be helpful if the drafting team could provide clarity on what to provide as evidence if no joint owners are identified.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

SRP agrees with Requirement R4 addressing the SARs concern about joint ownership.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

Southern Company agrees with Requirement R4 with the below suggestion for consideration:

The removal of including “documentating a risk assessment methodology under Requirement R3”. This is redundant since any Transmission Owner performing Requirement R5 must have a risk assessment methodology for the stations being assessed per Requirements R1, R2, and R4.

R4.
Each Transmission Owner with applicable Transmission station(s) and Transmission substation(s) identified in Requirement R1 containing Bulk Electric System (BES) Elements owned by multiple Transmission Owners shall coordinate with each appropriate Transmission Owner(s) to determine and document their individual and joint responsibilities for documenting a risk assessment methodology under Requirement R3 and for performing any required risk assessments per Requirement R5.

Likes 0	
Dislikes 0	

Response

Misty Carneal - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF

Answer	Yes
Document Name	

Comment

Duke Energy agrees with the modifications made to R4.

Likes 0	
Dislikes 0	

Response

Nikki Carson-Marquis - Nikki Carson-Marquis On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Nikki Carson-Marquis	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy Peters - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
: It makes sense to coordinate in cases where there are joint owners	
Likes 0	
Dislikes 0	
Response	
Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the modifications made in R4	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	

Answer	Yes
Document Name	
Comment	
ATC agrees with MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	Yes
Document Name	
Comment	
MEC has no 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	
MRO NSRF has concerns that there may be situations in which an auditor asks a Registered Entity to produce evidence proving a negative, i.e. that one or more subs are solely owned. M4 discusses how to show evidence that you've coordinated with joint owners, but it would be helpful if the drafting team could provide clarity on what to provide as evidence if no joint owners are identified.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Emma Halilovic - Hydro One Networks, Inc. - 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	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
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	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dan Perry - TXNM Energy - 1,3,5 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wesley Maurer - Lower Colorado River Authority - 1 - Texas RE	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Joseph Scott - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
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	

Robert Follini - Avista - Avista Corporation - 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	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
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	
Lincoln Burton - Con Ed - Consolidated Edison Co. of New York - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Phillip Martinez - Phillip Martinez On Behalf of: Richard Jackson, U.S. Bureau of Reclamation, 1, 5; - U.S. Bureau of Reclamation - 1 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jodi Yeary - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
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	
Darko Kovac, P.E. - Gainesville Regional Utilities - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Breen - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
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	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tamarra Hardie - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD	
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	

Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lexi Dobrzysnki - Lexi Dobrzysnki On Behalf of: Angela Dockter, Alliant Energy Corporation Services, Inc., 4; - Lexi Dobrzysnki	
Answer	
Document Name	
Comment	
Alliant Energy mirrors the MRO NSRF group Comments.	
Likes 0	
Dislikes 0	
Response	

5. Do you agree with the modifications made in CIP-014-4 with adding Requirement R5 to address the issues identified in the SAR? If you do not agree, please provide your recommendation and, if appropriate, technical or procedural justification.

Jeffrey Streifling - NB Power Corporation - 1

Answer	No
Document Name	
Comment	

Clarify if at the end of the 36-month period the entity must have the Risk Assessment started or completed? TFIST suggest splitting the operational assessment and security assessment into distinct assessments in the timeline to reduce confusion, and not just the “risk assessment”.

Likes 0	
Dislikes 0	
Response	

Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	
Comment	

BPA believes R5 is missing a requirement to coordinate in order to ensure data from proximate Transmission stations and sub-stations can be obtained and validated. Without a requirement to coordinate, BPA believes there would be difficulty identifying the Primary Control Center operationally controlling the proximate Transmission stations and sub-stations. BPA also recommends adding language to R5 to clarify how a Registered Entity should address negative responses from proximate substation owners.

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	

There is no issue with performing a risk assessment every 36 months. However, Transmission Owners are not the appropriate registered entity to conduct planning analyses. Nor are the CIP standards the appropriate place to document planning analysis requirements. Planning studies should be governed within the TPL group of standards.

Likes 0	
Dislikes 0	
Response	

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
TEPC agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FirstEnergy asks for clarification of responsibilities toward R5 - specifically as realted to unregistered DERs and IBRs.

FirstEnergy also supports EEI's comments which state:

EEI suggests the following revisions to Requirement R5.

The revised draft CIP-014-4 Requirement R5 includes a new statement: “If proximate Transmission station(s) and Transmission substation(s) were identified in Requirement R2, they should also be

included in the risk assessment.” The word “should” could be interpreted as a recommendation instead of a mandatory requirement.

Additionally, by referring to “proximate Transmission station(s) and Transmission substation(s)… identified in Requirement R2” in Requirement R5, all identified proximate Transmission station(s) and Transmission substation(s) would be subject to Requirements R8-R10, not just those that are applicable.

If it is the intention of the drafting team to require applicable proximate Transmission station(s) and Transmission substation(s) to be included in the Requirement R5 risk assessment, EEI suggests the following:

R5. At least once every 36 calendar months, each Transmission Owner shall perform a risk assessment to identify applicable Transmission station(s) and Transmission substation(s) identified in Requirement R1, that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an interconnection, using the methodology established in Requirement R3, including any Transmission station(s) and Transmission substation(s) identified in accordance with Requirement R4.

EEI also asks the drafting team to consider adding information to the technical rationale discussing scenarios where a new risk assessment demonstrates that a substation is no longer applicable to CIP-014, but a previous physical security plan includes security measures with future due dates. The technical rationale could include discussion of actions to take when security measures are no longer required for the de-classified transmission substation(s).

Likes 0	
Dislikes 0	

Response

David Melanson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5

Answer	No
Document Name	

Comment

NB Power supports NPCCs comments:

"R5. Please clarify whether, at the end of the 36-month period, the entity is required to have initiated or completed the Risk Assessment. NPCC RSC recommends separating the operational assessment and security assessment into distinct components within the timeline to reduce confusion, rather than referring to both collectively as the “risk assessment.”
In the final sentence of R5, the phrase “they should also be included in the risk assessment” raises a question: does this imply that proximate Transmission station(s) and Transmission substation(s) are optional in the risk assessment?"

Likes 0	
Dislikes 0	

Response

Nikki Carson-Marquis - Nikki Carson-Marquis On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Nikki Carson-Marquis

Answer	No
Document Name	

Comment

MPC strongly disagrees with the use of a 36-month timeframe for utilities who have not previously identified any Transmission stations or substations as critical as it will lead to increased study costs with little or no benefit to the reliability of the BES. Instead, MPC proposes retaining the requirement to perform a risk assessment every 60 months for TOs that have not previously identified applicable Transmission stations or substations, and include Transmission station(s) and Transmission substation(s) planned to be in service within 60 calendar months.

SAR objective number 2 states a goal for this project is to “correct any discrepancies between the study period, frequency of study, and the base case(s) a Transmission Owner uses.” This is the basis for the SDT’s justification to change the risk assessment timeframe from 60 months for TOs without applicable Transmission stations or substations to 36 months for all TOs without exception. Further, the Technical Rationale states the change to 36 months was to align the CIP-014 risk assessment with the annual model build time frame of Standard TPL-001. Because the CIP-014 analysis does not depend on the models built for TPL-001, MPC believes changing the risk assessment time frame to align with the TPL-001 model build process does not provide benefit to the CIP-014 analysis. Additionally, the existing 60 month timeframe for TOs without applicable Transmission station(s)/substation(s) still aligns with the 12-month model build timeframe of the TPL-001 standard.

MPC continues to hold the position that given the very slow pace of construction of new electrical infrastructure due to increased equipment lead times, supply chain constraints, and labor shortages, 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 (sub)station 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 new Transmission stations or substations that would not be identified under CIP-014-3.

For utilities who have not identified previously identified (sub)stations as critical, moving the risk assessment timeframe from 60 calendar months to 36 calendar months will result in increased costs due to more frequent risk assessments, with the more frequent assessments having no BES reliability benefit as they have little to no chance of identifying stations or substations as CIP-014 critical that would not already have been under the CIP-014-3.

Likes 0	
Dislikes 0	

Response

Isidoro Behar - Long Island Power Authority - 1

Answer	No
Document Name	

Comment

In general, we recommend that the wording in the main requirement section of Req #5 be reviewed in detail for clarity.

Requirement #5 states:

"*At least once every 36 calendar months, each Transmission Owner shall perform a risk assessment to identify applicable Transmission station(s) and Transmission substation(s) identified in Requirement R1, that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection, using the methodology established in Requirement R3, including any Transmission station(s) and Transmission substation(s) identified in accordance with Requirement R4. If proximate Transmission station(s) and Transmission substation(s) were identified in Requirement R2, they should also be included in the risk assessment.*"

a) This requirement introduces the concept of "*that if rendered inoperable or damaged*". While the verbiage **"that if rendered inoperable or damaged"** may be introduced within the Technical Rationale, this verbiage is confusing when reading Req #5 – and as such it is recommended to correlate what is meant by "that if rendered inoperable or damaged" within Requirement #3 (or introduce this concept within the Req #3). Requirement #3 mentions "the loss of each applicable Transmission station or Transmission substation identified in Requirement R1" – with no mention or correlation of "loss of each station" to "that if rendered inoperable or damaged".

b) The verbiage states "using the methodology established in Requirement R3, including any Transmission **station(s)** and Transmission **substation(s)** identified in accordance with Requirement R4". However, as written, Req #4 relates to the coordination with respect to "**Bulk Electric System (BES) Elements** owned by multiple Transmission Owners". As written, Req #4 does not identify "stations".

c) The verbiage states "If proximate Transmission station(s) and Transmission substation(s) were identified in Requirement R2, they **should** also be included in the risk assessment."

This implies that the inclusion of proximate stations in the risk assessment is optional. If this is a requirement, the term "should" should be replaced by "shall".

d) The verbiage states "If **proximate** Transmission station(s) and Transmission substation(s) were identified in Requirement R2, they **should** also be included in the risk assessment." This requirement is not clear and needs clarification.

- This wording contradicts with the wording in Req #3 which states: "*Each Transmission Owner shall have a documented risk assessment methodology for evaluating the loss of each* ***applicable*** *Transmission station or Transmission substation identified in Requirement R1.*"
- Does this mean that requirements 7 through 10 apply to proximate stations if the fault on the proximate station leads to instability, uncontrolled separation, or Cascading within an Interconnection?
- For proximate stations, it is required to identify them and apply a fault on them. For the risk assessment, what specifically needs to be done for the proximate stations?

e) Please clarify whether, at the end of the 36-month period, the entity is required to have initiated or completed the Risk Assessment. We recommend separating the operational assessment and security assessment into distinct components within the timeline to reduce confusion, rather than referring to both collectively as the "risk assessment."

Likes 0	
Dislikes 0	
Response	
Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	No
Document Name	
Comment	

Black Hills Corporation agrees with EEI's recommended changes to the language in Requirement R5. This change makes it clear which proximate Transmission stations and Transmission substations should be included in the scope for all requirements. The current language could cause confusion as to which proximate Transmission station/substations need to be included for each requirement, thus expanding the scope of the standard further than is intended. Black Hills Corporation also agrees with EEI's suggestion to add information to the technical rationale for scenarios where a risk assessment demonstrates a previously applicable substation no longer is, and what actions to take when security measures are no longer required for a specific substation.

Likes 0	
Dislikes 0	
Response	

Misty Carneal - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy supports EEI's recommendation that the Drafting Team replace "should" in the last sentence of paragraph one with "shall".	
Likes 0	
Dislikes 0	
Response	
Steven Belle - Dominion - Dominion Virginia Power - 1	
Answer	No
Document Name	
Comment	
Dominion supports EEI's comments.	
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	
R5. Please clarify whether, at the end of the 36-month period, the entity is required to have initiated or completed the Risk Assessment. NPCC RSC recommends separating the operational assessment and security assessment into distinct components within the timeline to reduce confusion, rather than referring to both collectively as the "risk assessment." In the final sentence of R5, the phrase "they should also be included in the risk assessment" raises a question: does this imply that proximate Transmission station(s) and Transmission substation(s) are optional in the risk 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 Institute for question #5.	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	
“Rendered inoperable” should be eliminated from this standard. This term has no definition and leads the RE to move toward a requirement to study the “Smoking Crater” scenario. There has been no documented “Smoking Crater” scenario documented on US soil at a BES substation and to force TO’s to develop fault scenarios for an unrealistic event is unreasonable.	
Likes 1	Nebraska Public Power District, 5, Bender Ronald
Dislikes 0	
Response	
Zahid Qayyum - New York Power Authority - 5	
Answer	No
Document Name	
Comment	
NYPA supports NPCC RSC comments.	
Likes 0	
Dislikes 0	

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

Recommend removing “including any Transmission station(s) and Transmission substation(s) identified in accordance with Requirement R4. If proximate Transmission station(s) and Transmission substation(s) were identified in Requirement R2, they should also be included in the risk assessment.” from R5.

Rational for removing:

This language is redundant because the inclusion of proximate substations within the risk assessment methodology is already established by the previous Requirements (R2 and R3.3.2) and therefore will inherently be included in the risk assessment. Adding this to Requirement R5 could potentially add confusion. Proximate substations, irrespective of ownership, must be included in the risk assessments; but Requirement R5 is talking about performing the risk assessment and identifying the applicable stations (owned by the TO performing the Risk Assessment) from Requirement R1 that could result in instability, uncontrolled separation, or Cascading within an Interconnection…

Proximate substations owned by different TOs could have different Methodologies. A proximate substation not owned by the TO performing the risk assessment cannot be identified as “critical – that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading” by that TO, even though the proximate substations will be included within the risk assessment based on Requirements R2 and R3. If this redundant language isn’t removed, it could add confusion around this.

The language pointing back to Requirement R4: “...including any Transmission stations(s) and Transmission substation(s) identified in accordance with Requirement R4.” is also not needed and redundant. It doesn’t add confusion in the way the reference back to proximate substations does, but it is still unnecessary. Requirement R4 talks about coordinating the responsibilities if there are BES Elements owned by multiple TOs within a substation already identified in Requirement R1. **The list of substations identified by Requirement R1 are the “superset” and therefore all that is needed in Requirement R5 is point back to R1** (not R4).

Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 10, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	

R5. Please clarify whether, at the end of the 36-month period, the entity is required to have initiated or completed the Risk Assessment. NPCC RSC recommends separating the operational assessment and security assessment into distinct components within the timeline to reduce confusion, rather than referring to both collectively as the “risk assessment.”

In the final sentence of R5, the phrase “they should also be included in the risk assessment” raises a question: does this imply that proximate Transmission station(s) and Transmission substation(s) are optional in the risk assessment?

Likes 0	
Dislikes 0	
Response	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	No
Document Name	
Comment	
Ameren agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
"Please see EEI Comments"	
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

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

Answer	No
Document Name	

Comment

EEI suggests the following revisions to Requirement R5.

The revised draft CIP-014-4 Requirement R5 includes a new statement: “If proximate Transmission station(s) and Transmission substation(s) were identified in Requirement R2, they should also be included in the risk assessment.” EEI suggests removing this sentence because Requirement R5 already requires TOs to perform a risk assessment using the methodology established in Requirement R3, and Requirement R3 part 3.3.2 includes Transmission station(s) and Transmission substation(s) determined in accordance with Requirement R2 as being in proximity to an applicable Transmission station or Transmission substation.

Additionally, including a separate reference to “proximate Transmission station(s) and Transmission substation(s)… identified in Requirement R2” in Requirement R5, could be confused for an expansion in scope because, as written, the reference is to identified proximate Transmission station(s) and Transmission substation(s) in Requirement R2, not those that are identified through the performance of the Requirement R5 risk assessment. The scope of Requirement R5 is important because of its tie to Requirements R8-R10.

EEI suggests the following:

R5. At least once every 36 calendar months, each Transmission Owner shall perform a risk assessment to identify applicable Transmission station(s) and Transmission substation(s) identified in Requirement R1, that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an interconnection, using the methodology established in Requirement R3, including any Transmission station(s) and Transmission substation(s) identified in accordance with Requirement R4.

EEI also asks the drafting team to consider adding information to the technical rationale discussing scenarios where a new risk assessment demonstrates that a substation is no longer applicable to CIP-014, but a previous physical security plan includes security measures with future due dates. The technical rationale could include discussion of actions to take when security measures are no longer required for the de-classified transmission substation(s).

Likes 0	
Dislikes 0	

Response

Joseph Scott - Lower Colorado River Authority - 5

Answer	No
Document Name	

Comment

We do not agree with the changes to R5 as currently written. Please see our responses to question 2 and 3. We share the same concerns regarding data availability, regional boundaries, and practicality of assessing proximate substations outside of our control.	
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	

For 5.1, failure to perform the entirety of the risk assessment could have an TO not completing either the stability of steady state portion of the study. If the third party reviewer identified a mistake in the piece of the study that was completed, they have nothing to verify for the second half of the study as it was not performed. Changes to the system which add resiliency to the system may have changed a previous critical station to a non-critical station. Not studying it going forward means that the costs would continue to be incurred for protecting a station that does not require it.

ITC also suggests the following revisions to Requirement R5.

The revised draft CIP-014-4 Requirement R5 includes a new statement: “If proximate Transmission station(s) and Transmission substation(s) were identified in Requirement R2, they should also be included in the risk assessment.” EEI suggests removing this sentence because Requirement R5 already requires TOs to perform a risk assessment using the methodology established in Requirement R3, and Requirement R3 part 3.3.2 includes Transmission station(s) and Transmission substation(s) determined in accordance with Requirement R2 as being in proximity to an applicable Transmission station or Transmission substation.

Additionally, including the separate reference to “proximate Transmission station(s) and Transmission substation(s)… identified in Requirement R2” in Requirement R5, could be confused for an expansion in scope because, as written, the reference is to identified proximate Transmission station(s) and Transmission substation(s) in Requirement R2, not those that are identified through the performance of the Requirement R5 risk assessment. Furthermore R4 should not be included in R5. Only stations identified in R1 need to be reviewed to determine if they are jointly owned. R4 should only identify those stations identified in R1 that an entity would no longer need to study as the other joint owner will be performing it. The scope of Requirement R5 is important because of its tie to Requirements R8-R10.

ITC suggests the following:

R5. At least once every 36 calendar months, each Transmission Owner shall perform a risk assessment to identify applicable Transmission station(s) and Transmission substation(s) identified in Requirement R1, that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an interconnection, using the methodology established in Requirement R3, excluding any Transmission station(s) and Transmission substation(s) identified in accordance with Requirement R4 to be reviewed by the entity identified in R4.. If proximate Transmission station(s) and Transmission substation(s) were identified in Requirement R2, they should also be included in the risk assessment.”

Likes 0	
Dislikes 0	
Response	

Wesley Maurer - Lower Colorado River Authority - 1 - Texas RE	
Answer	No
Document Name	
Comment	
We do not agree with the changes to R5 as currently written. Please see our responses to question 2 and 3. We share the same concerns regarding data availability, regional boundaries, and practicality of assessing proximate substations outside of our control.	
Likes 0	
Dislikes 0	
Response	

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis	
Answer	No
Document Name	
Comment	
PJM does not recommend relying on past risk assessments, and instead recommends status quo to ensure a more accurate assessment of the Transmission station or Transmission substations. This is based on PJM's observation of major planning assumption changes in recent years that have been impacting reliability analysis.	
Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	No
Document Name	
Comment	
See comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	

Emma Halilovic - Hydro One Networks, Inc. - 1	
Answer	No
Document Name	2023-06 Draft_3_Comment_Form.docx
Comment	
Modify to suite the recommendation given in the attached.	
Likes 0	
Dislikes 0	
Response	

Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
ATC agrees with MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	

Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	

Comment	
AZPS agrees with comments submitted by EEI on behalf of their members to request a sub bullet be added to include clarification around Requirement 9.3 if the substation is no longer classified as critical based on a new risk assessment.	
Likes 0	
Dislikes 0	
Response	
Randy Peters - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
It would be nice to add a clear requirement (5.4) that the previous risk assessment can also be used if there have been no significant changes to the network in the 3 years since the previous assessment	
Likes 0	
Dislikes 0	
Response	
Matt Carden - Southern Company - Southern Company Services, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Southern Company agrees with Requirement R5 but recommends removing the language added in Draft 3 “If proximate Transmission station(s) and Transmission substation(s) were identified in Requirement R2, they should also be included in the risk assessment”. This is addressed in the methodology required per Requirement R3.3 and could lead to misinterpretations of the scope of Requirement R5.	
Likes 0	
Dislikes 0	
Response	
Timothy Singh - Timothy Singh On Behalf of: Israel Perez, Salt River Project, 3, 6, 5, 1; Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; - Timothy Singh	
Answer	Yes

Document Name	
Comment	
SRP agrees with Requirement R5 addressing that risk assessments are performed every 36 months.	
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	
Clarification/Additonal Information requested: What is the Drafting Team expectation for physically protecting proximate stations owned by the entity? Are they to be treated the same as the applicable stations? What about protection of the proximate station if it is owned by another entity?	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
The remove of the ability to allow 60 calendar months for subsequent risk assessments when previous risk assessments did not identify any Transmission stations or Transmission substations tha if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection is not adequalety justified. The Technical Rational only states "…to reduce the periodicity options from previous versions…"	
Likes 0	
Dislikes 0	
Response	
Dan Perry - TXNM Energy - 1,3,5 - WECC,Texas RE	
Answer	Yes

Document Name	
Comment	
TXNM Energy agrees with EEI comments	
Likes 0	
Dislikes 0	
Response	
Lucinda Bradshaw - Lucinda Bradshaw On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Lucinda Bradshaw	
Answer	Yes
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
The ISO/RTO Council (IRC) Standards Review Committee (SRC) agrees that the SAR provides clarity.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	

ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.

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

As stated in our response to Questions 3 above:

To reduce the burden on smaller TOs of developing an R3 methodology and performing the R5 planning studies, consider providing an option for entities to use the list of transmission stations or substations obtained from the Attachment 1 analysis, as the input to R7 for primary control center determination, and as the input to R8 to begin the physical attack evaluation. Attachment 1 would therefore be an option as the R3 methodology that would then be applied in R5. R4 would still be required. The R6 third party review would be limited to a review of the Attachment 1 analysis.

Likes 0	
Dislikes 0	
Response	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 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	
Tamarra Hardie - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD	
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 0	
Dislikes 0	
Response	

Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 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	
Thomas Breen - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darko Kovac, P.E. - Gainesville Regional Utilities - 1,3,5	
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	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jodi Yeary - AEP - 3	
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	
Phillip Martinez - Phillip Martinez On Behalf of: Richard Jackson, U.S. Bureau of Reclamation, 1, 5; - U.S. Bureau of Reclamation - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lincoln Burton - Con Ed - Consolidated Edison Co. of New York - 3	
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	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
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	
Richard Vendetti - NextEra Energy - 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	
Kelley Sargent - Puget Sound Energy, Inc. - 3	

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	
Lexi Dobrzysnki - Lexi Dobrzysnki On Behalf of: Angela Dockter, Alliant Energy Corporation Services, Inc., 4; - Lexi Dobrzysnki	
Answer	
Document Name	
Comment	
Alliant Energy mirrors the MRO NSRF group Comments.	
Likes 0	
Dislikes 0	
Response	

6. Do you agree with the Implementation Plan for CIP-014-4? If you think an alternate timeframe is needed, please propose an alternate implementation plan with a detailed explanation.

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	No
Document Name	
Comment	
ITC believes there could be issues with identifying all of the proximity stations soon enough to identify their configurations and clearing times soon enough to perform all of the required studies. This is more of an issue as entities add facilities in additional states. The number of coordination agreements could also cause an issue in obtaining all of the required documentation.	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
Nextera supports EEI comments below: EEI is concerned that the implementation plan requires the initial risk assessment required by CIP-014-4 to be completed on or before the effective date of the Standard and does not provide a phased in approach. The modifications required by the proposed CIP-014-4 include new processes to be established prior to initiating new risk assessments. The proposed 24-month timeline is not reasonable for completing the initial risk assessment. EEI suggests allowing the initiation of CIP-014-4 risk assessments to occur on or before the effective date of the standard to allow additional time to modify programs.	
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	

Due to the varying risk assessment schedules of entities, the 24 month implementation plan could burden entities who have completed a risk assessment shortly before the effective date of CIP-014-4 and have limited resources to complete another one in a short amount of time. Proposed language: 36 months from the entity's last risk assessment completed or 36 months after the effective date of the standard, which ever is later. This will provide adequate time for entities to adjust to the additional criteria for the risk assessment methodology.

Likes 0	
Dislikes 0	

Response

Jamison Cawley - Nebraska Public Power District - 1

Answer	No
Document Name	

Comment

The requirements for an unaffiliated third-party verification of the TO's risk assessment should be removed entirely. This requirement has increased the cost, time and resources required for each TO to perform the risk assessment. We have found that the third-party verification is not used by the RE for any compliance enforcement actions. If the third-party verification provides no value to this process, it should not be included in the CIP-014 requirements. If the 36-month RA requirement is approved, this issue will only become more burdensome.

Likes 1	Nebraska Public Power District, 5, Bender Ronald
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

It potentially could be excessively burdensome on a Transmission Owner (TO) to be required to perform a new risk assessment study within 24 months of the effective implementation date of the revised CIP-014-4 standard. Additionally, limited resources may be available to complete a verification within 90 days of the effective date per Requirement R6.

For example, given the current CIP-014-3 R1.1 30 calendar month subsequent risk assessment requirement schedule for a TO which has substations identified under R1, the TO may currently be required to complete a subsequent R1 study as of September 30, 2025.

If the revised standard has an effective implementation date of October 1, 2025, the TO would be required to complete a new R1 study within 24 months of October 1, 2025. A more effective and efficient methodology is a phased approach based on the TO's completion date of the TO's most recent R1.1 subsequent risk assessment study.

Proposed Language: Each TO shall conduct its first assessment under CIP-014-4 within 36 calendar months after the effective date or within 36 calendar months after their last assessment under CIP-014-3, whichever occurs later.	
Likes 0	
Dislikes 0	
Response	
Jodi Yeary - AEP - 3	
Answer	No
Document Name	
Comment	
The implementation plan accelerates the compliance timeframe specified in the standard. 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. The implementation plan should be adjusted to 36 months.	
Likes 0	
Dislikes 0	
Response	
Nikki Carson-Marquis - Nikki Carson-Marquis On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Nikki Carson-Marquis	
Answer	No
Document Name	
Comment	
MPC holds the position that requiring completion of a CIP-014-4 risk assessment prior to the effective date of the Standard presents duplicative efforts coupled with limited study resources. MPC suggests that entities with a completed risk assessment per CIP-014-3 be required to follow the new assessment frequency once the Standard becomes effective in accordance with R5.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

Until clarification of R5 pertaining to alignment of dual ownership is made, FirstEnergy cannot support the Implementation Plan.	
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	
There should be some period of time after the standard becomes effective before the initial risk assessment should be completed. The recommendation is within 24 months following the effective date of this standard.	
Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA repeats it recommendation to use terminology like that found in other standards such as FAC-014-3 R6: “Requirement R6 shall be implemented by the Planning Coordinator or Transmission Planner following the effective date of FAC-014-3 when it begins its next cycle for conducting the studies to support its Planning Assessment." BPA believes the inclusion of this language would alleviate concerns about having to comply with a requirement prior to its mandatory enforcement date and help to reduce overall costs for the implementation of the changes.	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
See comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Lucinda Bradshaw - Lucinda Bradshaw On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Lucinda Bradshaw	
Answer	Yes
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

EEI agrees with the Implementation Plan for CIP-014-4, however, we note that there are additional revisions to CIP-014 that are part of Project 2021-03 to address IROLs. It would be beneficial to align the timelines in the implementation plans for these projects if possible.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

Minnesota Power supports EEI's comments.

Likes 0	
Dislikes 0	

Response

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper

Answer	Yes
Document Name	

Comment

No significant differences from previous draft that require additional comment.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

"Please see EEI Comments"

Likes 0	
Dislikes 0	

Response

Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers

Answer	Yes
Document Name	

Comment

Ameren agrees with EEI's comments.

Likes 0	
Dislikes 0	

Response

Misty Carneal - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF

Answer	Yes
Document Name	

Comment

Duke Energy agrees with the Implementation Plan.

Likes 0	
Dislikes 0	

Response

Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6

Answer	Yes
Document Name	

Comment

Black Hills Corporation agrees with the implementation plan for CIP-014-4, but in agreement with EEI, we think it would be beneficial to align the timelines of the implementation plans with the implementation plan for additional changes to CIP-014-4 that are part of Project 2021-03.

Likes 0	
Dislikes 0	

Response	
Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the Implementation Plan	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
ATC agrees with MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	

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	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC)	
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	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dan Perry - TXNM Energy - 1,3,5 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wesley Maurer - Lower Colorado River Authority - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joseph Scott - Lower Colorado River Authority - 5	

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	
Ruida Shu - Northeast Power Coordinating Council - 10, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Zahid Qayyum - New York Power Authority - 5	
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	
Timothy Singh - Timothy Singh On Behalf of: Israel Perez, Salt River Project, 3, 6, 5, 1; Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; - Timothy Singh	

Answer	Yes
Document Name	
Comment	
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	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lincoln Burton - Con Ed - Consolidated Edison Co. of New York - 3	
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	
Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Belle - Dominion - Dominion Virginia Power - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Phillip Martinez - Phillip Martinez On Behalf of: Richard Jackson, U.S. Bureau of Reclamation, 1, 5; - U.S. Bureau of Reclamation - 1 - WECC	
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	
Isidoro Behar - Long Island Power Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Melanson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy Peters - Manitoba Hydro - 1,3,5,6 - MRO	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
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	
Darko Kovac, P.E. - Gainesville Regional Utilities - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Breen - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
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	

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

Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
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 0	
Dislikes 0	
Response	

Tamarra Hardie - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD	
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	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE noticed the retirement date section refers to CIP-014 and it should refer to CIP-014-4.	
Likes 0	
Dislikes 0	
Response	
Lexi Dobrzysnki - Lexi Dobrzysnki On Behalf of: Angela Dockter, Alliant Energy Corporation Services, Inc., 4; - Lexi Dobrzysnki	
Answer	
Document Name	
Comment	
Alliant Energy mirrors the MRO NSRF group Comments.	
Likes 0	
Dislikes 0	
Response	

7. Do you believe there are alternatives or more cost-effective options to address the recommendations in CIP-014-4 to address the reliability issue of physical security? If so, please provide your recommendation and, if appropriate, technical, or procedural justification.

Jeffrey Streifling - NB Power Corporation - 1

Answer	No
Document Name	

Comment

TFIST has a concern with multiple pending standards may overlap due to the delayed approval process may cause increased cost on entities due to multiple implementation plans occurring at the same time.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

MRO NSRF does not have any alternatives to propose.

Likes 0	
Dislikes 0	

Response

Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	No
Document Name	

Comment

MEC supports the comments of the MRO NSRF

Likes 0	
Dislikes 0	

Response

Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
ATC agrees with MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
No comments toward cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
David Melanson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	No
Document Name	
Comment	
NB Power supports NPCCs comments: "NPCC RSC is concerned that multiple pending standards may overlap due to delays in the approval process. This could lead to increased costs for entities, as they may be required to implement multiple standards simultaneously. For example, we are particularly concerned about CIP-014 and CIP-002 becoming misaligned or out of sync."	
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 at a higher frequency.	
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	
NPCC RSC is concerned that multiple pending standards may overlap due to delays in the approval process. This could lead to increased costs for entities, as they may be required to implement multiple standards simultaneously. For example, we are particularly concerned about CIP-014 and CIP-002 becoming misaligned or out of sync.	
Likes 0	
Dislikes 0	
Response	
Zahid Qayyum - New York Power Authority - 5	
Answer	No
Document Name	
Comment	
NYPA supports NPCC RSC comments.	
Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 10, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	
NPCC RSC is concerned that multiple pending standards may overlap due to delays in the approval process. This could lead to increased costs for entities, as they may be required to implement multiple standards simultaneously. For example, we are particularly concerned about CIP-014 and CIP-002 becoming misaligned or out of sync.	
Likes 0	
Dislikes 0	
Response	

Lucinda Bradshaw - Lucinda Bradshaw On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Lucinda Bradshaw	
Answer	No
Document Name	
Comment	
The comments above demonstrate that additional clarity is needed on certain portions of this revised CIP-014-4. Without that additional clarity, Oncor cannot state that the proposed changes to CIP-014-3 are cost effective. As noted above, some of the proposed revisions create additional work for TOs that could increase the TOs' costs. For example, the revised Requirements R2 and R4 will require Oncor to develop, document, and implement new procedures and processes, as well as to develop and implement additional training concerning the new requirements and the new procedures and processes.	
Likes 0	
Dislikes 0	
Response	

Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Breen - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	No
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	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Randy Peters - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Phillip Martinez - Phillip Martinez On Behalf of: Richard Jackson, U.S. Bureau of Reclamation, 1, 5; - U.S. Bureau of Reclamation - 1 - WECC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Wendy Kalidass - U.S. Bureau of Reclamation - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lincoln Burton - Con Ed - Consolidated Edison Co. of New York - 3	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Timothy Singh - Timothy Singh On Behalf of: Israel Perez, Salt River Project, 3, 6, 5, 1; Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; - Timothy Singh	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
Answer	No
Document Name	
Comment	
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	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dan Perry - TXNM Energy - 1,3,5 - WECC,Texas RE	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
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 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. 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. BPA finds the inclusions of R2.1 and R2.2 are so broad as to compound the issues of cost without a large gain in security or reliability. BPA believes the increase in CIP-014 applicability may require more resources than some smaller Transmission Owners have at their disposal. This increase will not only strain the resources of those smaller Transmission Owners but those of larger size within a BA that may be called upon to assist.

Likes 0	
Dislikes 0	

Response

Tamarra Hardie - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD

Answer	Yes
Document Name	

Comment

Please see comments provided for R2. More technical guidance from NERC on damage distances for a variety of bomb treat types is desired and modifying the distance requirement in R2 to be based upon technically-supported damage distances rather than personnel evacuation mandates is recommended. Additionally in R2, allowing utilities the flexibility to provide rationale in their CIP-014 assessments for why any identified proximate stations within the provided distance should be excluded or if any different distances are used would lead to more realistic physical security scenarios being assessed and reduce the cost-burden of assessing scenarios that are beyond reasonable damage distances.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	
Comment	

Currently, CIP-014 requires Transmission Owners to conduct planning analyses, and then have these analyses reviewed by a third party verifier. Requirement 6.1 states the the third party verifier must be a registered Planning Coordinator, Transmission Planner, Reliability Coordinator, or have transmission planning or analysis experience. The TO is not the appropriate registered entity to conduct planning analyses. Our understanding is that this is the reason why the standard requires a third party verification by a PC, TP, or RC. Apparently, NERC agrees that the analysis is best suited for the PC, TP or RC function. Furthermore, the fact that the standard is being revised to assure an adequate and consistent approach in evaluating instability as well as the identification of infrastructure critical to the operation of the BPS, supports the premise that the TO-performed study followed by verification by an unaffiliated third party is not a sufficient method. The better method would be to have an affiliated TP or PC to conduct the analysis. It is not cost effective to require the TO to conduct a planning study and then pay an unaffiliated third party to review the study. This is especially true if the TO is also a registered TP or PC. The TP and PC are the best qualified to conduct such studies. Furthermore, since CIP-014 is being revised to be more prescriptive regarding what should be included in the study methodology, the need for third party verification is significantly decreased. GTC recommends that requirement to perform such an analysis be assigned to the TP or PC functions within the TPL group of standards.

Likes 0	
Dislikes 0	
Response	

Nikki Carson-Marquis - Nikki Carson-Marquis On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Nikki Carson-Marquis

Answer	Yes
Document Name	
Comment	

Rather than requiring Transmission Owners without identified applicable Transmission stations/substations to perform a risk assessment every 36 months, it would be much more cost effective to allow utilities without critical (sub)stations to continue to perform the risk assessment every 60 months. The concern that a 60 month assessment may not include all planned facilities before the subsequent risk assessment is performed 60 months later could be allayed by changing the requirement to include facilities planned to be in service within the next 60 months rather than the next 24 months as required in CIP-014-3.

Likes 0	
Dislikes 0	
Response	

Jodi Yeary - AEP - 3

Answer	Yes
Document Name	

Comment	
Yes. While this SAR focused on modification to R1, the standard could meet the intent of the original FERC order in a more cost effective manner by modifying subsequent requirements to allow for Transmission system reinforcement that would reduce the impact of damage to a Transmission station on the Interconnection as an alternative solution to physical security protections.	
Likes 0	
Dislikes 0	
Response	
Misty Carneal - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	Yes
Document Name	
Comment	
Duke Energy does not have any additional comments.	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
All of the extreme critical fault scenarios are already being evaluated under the TPL-001 standard which has clear definitions of how, where, what and why. This CIP-014 standard requires undocumented and undefined requirements be included in the risk assessment, which does not satisfy the original intent of the Physical Security Standard. If we want to increase physical security at BES substations, a clear bright line criteria should be established based on kV level and number of interconnections like other CIP standards. Inclusion of vague risk assessment criteria wastes valuable resources which could better be spent focusing on the transmission planning system performance and development of a more robust grid which is not susceptible to the loss of any single applicable substation.	
Likes 1	Nebraska Public Power District, 5, Bender Ronald
Dislikes 0	
Response	
Joseph Scott - Lower Colorado River Authority - 5	

Answer	Yes
Document Name	
Comment	

An alternative could be requiring a certain level of security be applied consistently across BES substations (i.e., not limited to CIP-014 substations).

These basic requirements could include: 1) security-grade perimeter fencing 2) remote surveillance via motion-sensing video cameras, and 3) local measures such as motion sensor-activated lighting and break-in audible alarms.

When applied at new substations or as these are improved over time, the incremental cost is not significant and supports a hardened system at a broader level.

Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	

The requirement for documentation is not cost effective. Requiring all entities to provide this documentation for historic stations is an administrative burden. This requirement should only be applicable to those entities who failed to perform a risk assessment for a joint station.

Likes 0	
Dislikes 0	
Response	

Emma Halilovic - Hydro One Networks, Inc. - 1

Answer	Yes
Document Name	2023-06 Draft_3_Comment_Form.docx
Comment	

The alternatives and cost-effective options are outlined in the attached.

Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1, Group Name Exelon	
Answer	Yes
Document Name	
Comment	
As stated in our response to Questions 3 & 5: To reduce the burden on smaller TOs of developing an R3 methodology and performing the R5 planning studies, consider providing an option for entities to use the list of transmission stations or substations obtained from the Attachment 1 analysis, as the input to R7 for primary control center determination, and as the input to R8 to begin the physical attack evaluation. Attachment 1 would therefore be an option as the R3 methodology that would then be applied in R5. R4 would still be required. The R6 third party review would be limited to a review of the Attachment 1 analysis.	
Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darko Kovac, P.E. - Gainesville Regional Utilities - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Wesley Maurer - Lower Colorado River Authority - 1 - Texas RE	
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	

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	

Lexi Dobrzysnki - Lexi Dobrzysnki On Behalf of: Angela Dockter, Alliant Energy Corporation Services, Inc., 4; - Lexi Dobrzysnki	
Answer	
Document Name	
Comment	

Alliant Energy mirrors the MRO NSRF group Comments.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	
Document Name	
Comment	
PGAE does not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Josh Schumacher - Black Hills Corporation - 6, Group Name Black Hills Corporation Segments 1, 3, 5, 6	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	

Likes 0	
Dislikes 0	

Response

Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers

Answer	
Document Name	

Comment

Ameren will not comment on the cost effectiveness of the project.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

EEI does not comment on cost.

Likes 0	
Dislikes 0	

Response

8. Provide any additional comments for the Drafting Team to consider, if desired.

Emma Halilovic - Hydro One Networks, Inc. - 1	
Answer	
Document Name	2023-06 Draft_3_Comment_Form.docx
Comment	
System-wide performance evaluation is the accountability of the Reliability Coordinators. Therefore, if the standard must have system-wide (Interconnection) performance testing and judgement of results, the RC must be involved. Not every facility owner will be able to do this. The standard should be practical to implement. See attached for comments.	
Likes 0	
Dislikes 0	
Response	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	

Usama Tahir - Seminole Electric Cooperative, Inc. - 3	
Answer	
Document Name	
Comment	
Seminole Electric Cooperative would like clarification on: 1. In Attachment 1 – Applicability Criteria, If a generator has a Collector bus, but the collector bus also serves as a Transmission Facility, how is it classified? Is it classified as a collector bus or Transmission Facility?	

2. How to classify a transmission station/substation that has one line that exits, has a tap half a mile out for example, then goes to two separate Transmission Facilities? How do we count the weight of the transmission station/substation that has one line exiting but it systematically connected to two Transmission Facilities? 3. In requirement R2, are proximate Transmission stations in scope even if they are not BES?	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	
Document Name	
Comment	
Seminole Electric Cooperative would like clarification on: 1. In Attachment 1 – Applicability Criteria, If a generator has a Collector bus, but the collector bus also serves as a Transmission Facility, how is it classified? Is it classified as a collector bus or Transmission Facility? 2.. How to classify a transmission station/substation that has one line that exits, has a tap half a mile out for example, then goes to two separate Transmission Facilities? How do we count the weight of the transmission station/substation that has one line exiting but it systematically connected to two Transmission Facilities? 3. In requirement R2, are proximate Transmission stations in scope even if they are not BES?	
Likes 0	
Dislikes 0	
Response	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	
Document Name	
Comment	
The ISO/RTO Council (IRC) Standards Review Committee (SRC) notes that Criterion 3 in Attachment 1 references Facilities identified by the Planning Coordinator as critical to the derivation of an Interconnection Reliability Operating Limit (IROL). However, under FAC-014-3, Planning Coordinators no longer develop IROLs. The SRC recommends that criterion 3 be updated accordingly to remove the reference to the Planning Coordinator. The SRC also recommends that the drafting team revise the Technical Rationale to indicate whether the unaffiliated third-party validation under Requirement R6 requires the third party to validate the risk assessments completed in accordance with both Requirements R1 and R2 or just	

Requirement R1. The current Technical Rationale only indicates that validation of Requirement R1 risk assessments is required. The Technical Rationale should also be updated to more clearly correct and clarify all references to requirements to align with the newly proposed CIP-014-4 Requirements R1-R5.

Alternatively, a new SAR could be developed to remove Requirement R6 from the proposed CIP-014-4 standard. The new requirements proposed in CIP-014-4 Requirements R1-R5 outline necessary specifics for more meaningful risk assessments, which reduces the need for unaffiliated third-party verification, especially given that auditors are also directed to apply various methods to test the validity of station identifications under current CIP-014-3 Requirement R1.[1]

[1] CMEP Practice Guide CIP-014-2

Likes 0	
Dislikes 0	

Response

Lucinda Bradshaw - Lucinda Bradshaw On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Lucinda Bradshaw

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Bret Galbraith - Seminole Electric Cooperative, Inc. - 6

Answer	
Document Name	

Comment

Seminole Electric Cooperative would like clarification on:

1. In Attachment 1 – Applicability Criteria, If a generator has a Collector bus, but the collector bus also serves as a Transmission Facility, how is it classified? Is it classified as a collector bus or Transmission Facility?

2. How to classify a transmission station/substation that has one line that exits, has a tap half a mile out for example, then goes to two separate Transmission Facilities? How do we count the weight of the transmission station/substation that has one line exiting but it systematically connected to two Transmission Facilities?

3. In requirement R2, are proximate Transmission stations in scope even if they are not BES?

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Minnesota Power supports MRO-NSRF comments.

Likes 0	
Dislikes 0	

Response

Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers

Answer	
Document Name	

Comment

We suggest changing the wording of the VSLs so they are not so burdensome.

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	
Document Name	

Comment

Understanding that R6, formerly R2 under CIP-014-3, is out of scope for this SAR, WAPA recommends a SAR be drafted to remove R6 as an administrative burden that should no longer be needed, given that this project has added the necessary specifics required for a meaningful risk assessment, diminishing the need for third-party verification. Also, there has been anecdotal experience as an industry that auditors have audited the (CIP-014-3) R1 risk assessments directly without relying on the R2 third-party verification as directed by the RSAW. If (CIP-014-4) R6 is to be retained,

90 calendar days for completing R6 in R6.2 is proving to be tight for some larger entities, which request extension to 180 calendar days (which would be much easier to calculate as six calendar months to avoid getting tripped up on 28/30/31-day months).

Likes 0	
Dislikes 0	
Response	
Rebika Yitna - Rebika Yitna On Behalf of: Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	
Document Name	
Comment	
No additional comments	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
Answer	
Document Name	
Comment	
This standard does not use the glossary term "Facility" other than in Attachment 1 and the exemption portion of 4.1.2 in the Applicability section; this creates ambiguity on whether the proximate stations identified in R2 are required to meet BES criteria or not. Strategic use of that term may alleviate some of the confusion around that requirement expressed during the webinar.	
Likes 0	
Dislikes 0	
Response	
Zahid Qayyum - New York Power Authority - 5	
Answer	
Document Name	
Comment	

- NYPA still believes that Requirement R2 remains vague and open to varied interpretations. For example, under R2 when evaluating the proximate transmission substations, the language in R2 is unclear whether any BES transmission station regardless of its voltage level should be assessed if it falls within 1,500 feet of a station identified in R1. We recommend SDT should give guidance in the standard itself if possible. The proximity of 1500ft tends to have more impact in urban cities therefore we recommend the SDT to consider this situation as well.
- Also regarding R3.1, it would be helpful if the SDT could provide guidance on the 'minimum' threshold for identifying unacceptable generation or load loss to support more consistent interpretation and understanding.
- Many interconnections projects, at least in the NPCC region, put a placeholder of in-service date of within 3 years, but these dates are often extended based on project specific timelines. Requiring a 36 month risk assessment (R1) would force TOs to study those projects which may not materialize within the said timeline or likely to have their ISDs extended, placing an unnecessary burden on TO's planning and study resources.

Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	
Document Name	
Comment	

- Under R2 clarify if "proximate" substation voltages must be 200kV and above or if the scope included all BES voltages.
- Technical Rationale for R3 part 3.4 states: *"the term "inoperable" includes the total loss of communication and protection equipment at the substation, necessitating delayed clearance from far-end relaying to isolate the event's impacts."* Clarify if this total loss of equipment is for only the applicable substation or also includes the proximate substation equipment.
- The Technical Rationale should clarify that fault type and fault location in a substation will be defined in the TO methodology.
- Per the 7/8/25 WebEx Q&A "the standard is silent" on what voltages to simulate faults on in a single substation with multiple voltages (ex 345kV with 230kV or 115kV). The Technical Rationale should clarify that this can be defined in the TO methodology.
- The Technical Rationale should clarify if the intent of the standard is for simultaneous faults to be simulated at applicable and proximate substations per the statements made on the 7/8/25 WebEx Q&A.

Likes 1	Nebraska Public Power District, 5, Bender Ronald
Dislikes 0	
Response	
Lincoln Burton - Con Ed - Consolidated Edison Co. of New York - 3	
Answer	
Document Name	
Comment	

This standard does not use the glossary term "Facility" other than in Attachment 1 and the exemption portion of 4.1.2 in the Applicability section; this creates ambiguity on whether the proximate stations identified in R2 are required to meet BES criteria or not. Strategic use of that term may alleviate some of the confusion around that requirement expressed during the webinar.

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 MRO NSRF for question #8.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE noticed the clean and redlines versions of CIP-014-4 do not match. The clean shows the subparts of Parts 3.3 and 3.4 as bullets, whereas the redline version shows them as numbers.

Likes 0	
Dislikes 0	

Response

Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6

Answer	
Document Name	

Comment

This standard does not use the glossary term "Facility" other than in Attachment 1 and the exemption portion of 4.1.2 in the Applicability section; this creates ambiguity on whether the proximate stations identified in R2 are required to meet BES criteria or not. Strategic use of that term may alleviate some of the confusion around that requirement expressed during the webinar.

Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	
Answer	
Document Name	
Comment	
This standard does not use the glossary term "Facility" other than in Attachment 1 and the exemption portion of 4.1.2 in the Applicability section; this creates ambiguity on whether the proximate stations identified in R2 are required to meet BES criteria or not. Strategic use of that term may alleviate some of the confusion around that requirement expressed during the webinar.	
Likes 0	
Dislikes 0	
Response	
Matt Carden - Southern Company - Southern Company Services, Inc. - 1	
Answer	
Document Name	
Comment	
Under "Purpose" we prefer the previous language of "as a result of". Southern Company recommends swapping Requirement R3 and R4 chronologically. This follows a more logical approach of identifying the stations and responsibilities to perform the assessment in the first three requirements followed by an assessment methodology in R4 and the performance of an assessment in R5. Southern Company recommends removing Requirement R6. With the understanding that this is not explicitly in scope of the current SAR, the added specificity of the proposed standard eliminates the reliability benefit of the third-party verifier. Additionally, based on a previous audit of CIP-014-3, Southern Company did not observe the Regional Entity take into consideration the review by the R2 third party verifier. If this is consistent across other Regional Entities, then an elimination of CIP-014-4 R6 may be appropriate due to the extra cost and the lack of a reliability benefit.	
Likes 0	
Dislikes 0	
Response	
Misty Carneal - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	

Document Name	
Comment	

Duke Energy does not have any additional comments. Thank you for considering our comments.

Likes 0	
Dislikes 0	
Response	

Jodi Yeary - AEP - 3

Answer	
Document Name	
Comment	

AEP is supportive of the VSLs, except for R2. Currently, R2 only specifies a Severe VSL with specific reference to “fence line” in the VSL table. This increases the likelihood of severe violations being identified based on disagreements on the method of distance calculation, which is not a high risk reliability objective. Lower severity VSLs should be identified for R2.

Thank you for being so responsive to comments from the previous version to this version!

Likes 0	
Dislikes 0	
Response	

Isidoro Behar - Long Island Power Authority - 1

Answer	
Document Name	
Comment	

Similar to TPL-001-5.1 Requirement 2.6, we recommend that the SDT consider, and if applicable, outline under which specific circumstances past studies/results can be utilized for the CIP-014-4 risk assessment.

The possible use of past studies may reduce workload of entities and support a more cost effective option to address CIP-014-4 needs.

Likes 0	
Dislikes 0	
Response	

Nikki Carson-Marquis - Nikki Carson-Marquis On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Nikki Carson-Marquis	
Answer	
Document Name	
Comment	
MPC appreciates the SDT’s efforts and the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	

Randy Peters - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
Manitoba Hydro agrees with the modifications made for R5, especially the addition of the new sub-requirement R5.2. However, it will be hard for a third-party reviewer to verify a current assessment unless the results of the previous assessment are provided with the current assessment Manitoba Hydro recommends that requirement R6 be removed from the standard as it is overly administrative. The revisions made from this project specifically outline study requirements and an additional third party review of the study is no longer necessary. In addition, if there were minimal changes to the network from the previous third-party assessment, a new third party assessment provides very little value. The NERC Quality Review (QR) team may be able to assist with this change to make the standard more efficient and cost effective.	
Likes 0	
Dislikes 0	
Response	

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

Answer	
Document Name	

Comment

AZPS appreciates the clarifications included by the Drafting Team in this draft, however continues to seek additional clarifications regarding entity responsibilities or exclusion of responsibilities for non-owned/operated stations/substations within proximity of identified locations. AZPS seeks clarification on if a site is included as part of Requirement R2 and identified during the risk assessment per R5 but is owned by a different company how that applies to R8-R10.

Likes 0	
Dislikes 0	

Response

Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson

Answer	
Document Name	

Comment

Consider the addition of definitive or explicit trigger for Requirement R8 if the identification of the critical asset remains unchanged. Without this it creates a significant blind spot because the threat environment can evolve and shift dramatically over the 36-month cycle or even since the initial assessment or implementation of the required physical security controls. Without a built-in mechanism to re-evaluate threats entities may overlook new or emerging vulnerabilities, leaving critical assets exposed.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

NA

Likes 0	
Dislikes 0	

Response	
Thomas Breen - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1	
Answer	
Document Name	
Comment	
Support the comments of the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Lexi Dobrzysnki - Lexi Dobrzysnki On Behalf of: Angela Dockter, Alliant Energy Corporation Services, Inc., 4; - Lexi Dobrzysnki	
Answer	
Document Name	
Comment	
Alliant Energy mirrors the MRO NSRF group Comments.	
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 primary issue with this standard as it is written, and as this draft continues is the application of requirements/expectations appropriate for the Transmission Planner/Planning Coordinator function to the Transmission Owner instead. This reduces clarity on the types of studies to be performed to assess the extreme events identified in this standard.

Regarding R6:

With an attempt at clarifying study criteria, though they should be applied to the appropriate planning entity, there is no reason to maintain a requirement for an unaffiliated third party to perform a verification of a transmission planning analysis associated with the risk assessment. Instead of requiring planning entities be the third party verifier, they should just perform the study under clearly defined requirements in a TPL standard and communicate this information to the Transmission Owner. It is also important to note the third party verifying the risk assessment for this physical security standard is not required to have expertise in that area according to this requirement. Additionally, the SDT should consider removing the Reliability Coordinator as a potential third party verifier as that function does not perform the type of analysis being sought in this standard.

Additional Comment:

The analysis outlined in the CIP-014 standard is an evaluation of an extreme event and is based on transmission planning analysis. Currently, the existing TPL-001 standard requires the evaluation of extreme events, though, it is not specific to this particular substation outage analysis and corrective actions are not required for these events. Additionally, there are ongoing efforts to establish a separate standard to address the long-term planning analysis around extreme weather events. It would seem NERC and the industry are potentially missing an opportunity to consolidate requirements around the evaluation of extreme events better than what is currently provided for in the current construct of the existing and planned Reliability Standards. Consideration should be given by NERC to provide a better pathway to house long-term planning requirements around extreme event analysis within the TPL standards (not CIP) and specify the reliability analyses needed, the parameters for determining reliability, expectations for corrective actions, and the communication path from planning to owners and others with a reliability-related need for this information. The planning assessment/CAP required by TPL-001 is already required to be distributed to applicable owners. Clarifying the extreme event expectations in TPL-001 to specify the substation outage alluded to in CIP-014 is one pathway to better align standard requirements with the appropriate entity.

Likes 0	
Dislikes 0	

Response

Amy Key - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	
Document Name	

Comment

MEC supports the comments of the MRO NSRF

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Understanding that R6, formerly R2 under CIP-014-3, is out of scope for this SAR, MRO NSRF recommends a SAR be drafted to remove R6 as an administrative burden that should no longer be needed, given that this project has added the necessary specifics required for a meaningful risk assessment, diminishing the need for third-party verification. Also, there has been anecdotal experience as an industry that auditors have audited the (CIP-014-3) R1 risk assessments directly without relying on the R2 third-party verification as directed by the RSAW. If (CIP-014-4) R6 is to be retained, 90 calendar days for completing R6 in R6.2 is proving to be tight for some larger entities, which request extension to 180 calendar days (which would be much easier to calculate as six calendar months to avoid getting tripped up on 28/30/31-day months).

Likes 0	
Dislikes 0	

Response

Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

BPA appreciates the opportunity to comment. BPA recognizes CIP-014 and physical security are growing beyond the intent of the original standard. BPA recommends evaluating the need to add additional NERC registrations to the standard applicability to broaden the available information required within CIP-014-4. BPA has noticed a possible grammar error with the redline of the technical rationale. Under the Rationale for Requirement R3, Part 3.1, located in the second line of the second paragraph Transmission substation is repeated twice. BPA believes this was supposed to follow the NERC glossary of terms and read “Transmission stations or sub-stations.

Likes 0	
Dislikes 0	

Response

Sean Steffensen - IDACORP - Idaho Power Company - 1

Answer	
Document Name	

Comment

In reference to the proposed changes to CIP-014 Section 4.1.1, IPC recommends explicitly requiring an agreement between joint owners of Transmission stations or substations to designate which entity is responsible for conducting the risk assessment and physical security studies to ensure clarity and accountability.

Likes 0	
Dislikes 0	

Response

Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1

Answer	
Document Name	

Comment	
no comments.	
Likes 0	
Dislikes 0	
Response	