Comment Report

Project Name:	2015-08 Emergency Operations | EOP-005-3 and EOP-006-3
Comment Period Start Date:	10/26/2016
Comment Period End Date:	12/9/2016
Associated Ballots:	2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-005-3 AB 2 ST 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-005-3 NBP AB 2 NB 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-006-3 AB 2 ST 2015-08 Emergency Operations | EOP-005-3, EOP-006-3, EOP-008-2 EOP-006-3 NBP AB 2 NB

There were 53 sets of responses, including comments from approximately 44 different people from approximately 41 companies representing 9 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the revisions and clarifications made by the EOP SDT to standard EOP-005-2, Requirement R4 and parts? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

2. Do you agree with the revisions and clarifications made by the EOP SDT, based on industry comments, to revise the language “at least once each 15 calendar months” back to “annual” or “annually,” as drafted in EOP-005-02? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

3. Do you agree with the revisions and clarifications made by the EOP SDT to standard EOP-006-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

4. Do you agree with the revisions and clarifications made by the EOP SDT, based on industry comments, to revise the language “at least once each 15 calendar months” back to “annual” or “annually,” as drafted in EOP-006-02? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

5. Please provide any additional comments for the EOP SDT 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
Portland General Electric Co.	Angela Gaines	3	WECC	PGE - Group 1	Angela Gaines	Portland General Electric Company	3	WECC
					Barbara Croas	Portland General Electric Company	5	WECC
					Scott Smith	Portland General Electric Company	1	WECC
					Adam Menendez	Portland General Electric Company	6	WECC
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	RF
					Karl Kohlrus	Prairie Power, Inc.	1,3	SERC
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Ellen Watkins	Sunflower Electric Power Corporation	1	SPP RE
					Bill Watson	Old Dominion Electric Cooperative	3,4	SERC
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
Chris Gowder	Chris Gowder		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach	4	FRCC
					Jim Howard	Lakeland	5	FRCC

						Electric		
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utility Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steve Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Mark Brown	City of Winter Park	4	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	9	FRCC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Southern Company - Southern Company Services, Inc.	Marsha Morgan	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc	1	SERC
					Jennifer Sykes	Southern Company Generation and Energy Marketing	6	SERC
					R Scott Moore	Alabama Power Company	3	SERC

					William Shultz	Southern Company Generation	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,10	NPCC	RSC no Dominion	Paul Malozewski	Hydro One.	1	NPCC
					Guy Zito	Northeast Power Coordinating Council	NA - Not Applicable	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					David Ramkalawan	Ontario Power Generation	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	UI	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Si Truc Phan	Hydro Quebec	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Laura Mcleod	NB Power	1	NPCC
					MIchael Forte	Con Edison	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Kelly Silver	Con Edison	3	NPCC
					Peter Yost	Con Edison	4	NPCC
					Brian O'Boyle	Con Edison	5	NPCC

					Greg Campoli	NY-ISO	2	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					Silvia Parada Mitchell	NextEra Energy, LLC	4	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
Midwest Reliability Organization	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Chuck Lawrence	American Transmission Company	1	MRO
					Chuck Wicklund	Otter Tail Power Company	1,5	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administratino	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Shannon Weaver	Midcontinent Independent System Operator	2	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,5,6	MRO
					Tony Eddleman	Nebraska Public Power District	1,3,5	MRO
Southwest	Shannon	2	SPP RE	SPP	Shannon Mickens	Southwest	2	SPP RE

Power Pool, Inc. (RTO)	Mickens			Standards Review Group		Power Pool Inc.		
					James Nail	Independence Power and Light	3	SPP RE
					Jerry McVey	Sunflower Electric	1	SPP RE
					Robert Gray	Board of Public Utilities (BPU) Kansas City, KS	3	SPP RE
					Lonnie Lindekguel	Southwest Power Pool	2	SPP RE
					Chris Dodds	Westar Energy	1,3,5,6	SPP RE

1. Do you agree with the revisions and clarifications made by the EOP SDT to standard EOP-005-2, Requirement R4 and parts? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
The revisions as posted to R4 create redundant language. SRP recommends removal of the language requiring the TOP to "update" from R4. Additionally, It is also unclear how significant of a change "would change [the TOP's] ability to implement its restoration plan". This could work for many entities allowing administrative changes to the restoration plan without requiring RC approval. However, this language creates a potential for issues with R1, R2, and R5 which all reference an "approved restoration plan".	
Likes 1	Nick Braden, N/A, Braden Nick
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
While AEP supports the overall direction and efforts of this project team, and believe that the latest draft is an improvement to the previous version, we have chosen once again to vote negative on EOP-005-3. The text "upd to the RC when the modification would substantively change the TOP's ability to implement the restoration plan or impact the RC's ability to monitor and direct restoration efforts" is only included in the callout, and is not in any way included within the obligation itself. In addition, what might be considered a substanitive change could be very subjective. As a result, there is a risk of inconsistent interpretation of the obligation by Responsible Entities and Auditors alike. At the very least, verbiage within the callout should be moved, at least in part, to the obligations themselves. In addition, it may be beneficial to also provide some clarity as to what a substantive change *is* to supplement the examples already provided for what it *is not*. For example, additional scenarios could be given related to changes that increase restoration time significantly or change the primary cranking path. These examples of what would and would-not be sustanitive changes could be provided in a Guidelines and Techical Basis section	
Likes 0	
Dislikes 0	

Response	
Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Bonneville Power Administration (BPA) suggests revising the cause for submission of a revised restoration plan to "submit its revised restoration plan to its Reliability Coordinator for approval when a BES change would impact its ability to implement its restoration plan..."	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 5	
Answer	No
Document Name	
Comment	
Part 4.2 of the proposed standard is still unclear. If the intent is that the Transmission Operator submit its revised restoration plan to the Reliability Coordinator in time that it can be approved by the Reliabilty Coordinator and implemented by the Transmission Operator on the date the planned BES modifications are placed in-service, the requirement should simply state that. The proposed wording on part 4.2 is not clear what the intent is. R4 requires a Transmission Operator to "update and submit" its revised restoration plan for approval subject to parts 4.1 and 4.2. The phrase "subject to the Reliability Coordinator approval requirements per EOP-006" doesn't make sense when the requirement and part 4.2 are read in total.	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The proposed language of R4 is unclear. If the intent is that the Transmission Operator submit its revised restoration plan to the Reliability Coordinator in time that it can be approved by the Reliabilty Coordinator and implemented by the Transmission Operator on the date the planned BES modifications are placed in-service, the requirement should simply state that.	

The NSRF suggests changing R4 to read: “Each Transmission Operator, who identifies a change in its restoration plan that would affect its ability to implement its plan or its Reliability Coordinator’s ability to monitor and direct restoration efforts, shall, within 90 days, revise and submit its restoration plan to its Reliability Coordinator for approval.” Subrequirements, 4.1 and 4.2 can be deleted.

R4.2 refers to another standard, EOP-006. Requirements should refrain from referring to another standard and should stand on its own. The language, “prior to implemnenting a planned permanent BES modification” is ambiguious.

Likes 0	
Dislikes 0	

Response

Eric Ruskamp - Lincoln Electric System - 6

Answer	No
Document Name	

Comment

The proposed language of R4 is unclear. If the intent is that the Transmission Operator submit its revised restoration plan to the Reliability Coordinator in time that it can be approved by the Reliabilty Coordinator and implemented by the Transmission Operator on the date the planned BES modifications are placed in-service, the requirement should simply state that.

LES suggests modifing R4 as follows:

R4: “Each Transmission Operator, who identifies a change in its restoration plan that would affect its ability to implement its plan or its Reliability Coordinator’s ability to monitor and direct restoration efforts, shall, revise and submit its restoration plan to its Reliability Coordinator for approval.”

R4.1 “Within 90 calendar days after identifying any unplanned permanent BES modifications.

R4.2 “At least 30 days prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.” (EOP-006 just states that the RC shall determine whether the TOP’s restoration plan is coordinated with and compatible with other TOPs’ restoration plans within its RC Area. At least 30 days prior to will allow the RC the 30 days it is allowed for approval before the planned modification is energized.

Likes 0	
Dislikes 0	

Response

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer	No
Document Name	
Comment	

The rationale box expresses that Unplanned System Modifications could include Natural Disasters or major equipment failures.... and then suggests that outages are not unplanned system modifications; however most natural disasters and equipment failures results in outages. This does not clarify the intent of Unplanned System Modifications

Likes 0	
Dislikes 0	
Response	

larry brusseau - Corn Belt Power Cooperative - 1

Answer	No
Document Name	
Comment	

The proposed language of R4 is unclear. If the intent is that the Transmission Operator submit its revised restoration plan to the Reliability Coordinator in time that it can be approved by the Reliability Coordinator and implemented by the Transmission Operator on the date the planned BES modifications are placed in-service, the requirement should simply state that.

I suggests changing R4 to read: “Each Transmission Operator, who identifies a change in its restoration plan that would affect its ability to implement its plan or its Reliability Coordinator’s ability to monitor and direct restoration efforts, shall, within 90 days, revise and submit its restoration plan to its Reliability Coordinator for approval.” Subrequirements, 4.1 and 4.2 can be deleted.

R4.2 refers to another standard, EOP-006. Requirements should refrain from referring to another standard and should stand on its own. The language, “prior to implementing a planned permanent BES modification” is ambiguous.

Likes 0	
Dislikes 0	
Response	

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

Answer	No
Document Name	
Comment	

As written the language causes confusion regarding the TOP's ability to implement changes to its restoration; language implies that a revised plan would change the entitiy's ability to implement that revised plan. To remedy this it is suggested that the SDT consider making changes to the effect as follows:

R4. *Each Transmission Operator shall update and submit its revised restoration plan to its Reliability Coordinator for approval, when the revision would change its ability to implement its the currently approved RC restoration plan, as follows: [Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

4.1. *Within 90 calendar days after identifying any unplanned permanent BES modifications.*

4.2. *Prior to implementing a planned permanent BES modification subject to the Reliability Coordinator approval requirements per EOP-006.*

In addition, the implementation period for the revised restoration plan's approval creates a compliance time gap that could result with potentially different interpretations between auditors, entities, and the RC. During the timeframe of RC reviewing and approving an entity's revised restoration plan, it would be helpful to identify a defined period that allows implementation of an entity's revised plan that provides implementation of the "unapproved" plan to be valid through the end of the RC approval process.

Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	

We believe the wording of the requirement could be improved to better reflect the apparent intent. The words "revised" and "revision" are used in different contexts in the same sentence which causes confusion. Also, system modifications may not be the only reason to update the plan. We suggest the wording be modified to something along the lines of:

R4. Each TOP shall update and resubmit its restoration plan to its RC for review and approval, when a System modification or other change has or will occur which invalidates or makes the approved plan unable to be implemented. Such updates shall be made as follows: 4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications. 4.2 Prior to implementing a planned permanent BES modification or procedural change subject to the RC approval requirements per EOP-006.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
WAPA supports the suggestion of changing R4 to read: "Each Transmission Operator, who identifies a change in its restoration plan that would affect its ability to implement its plan or its Reliability Coordinator's ability to monitor and direct restoration efforts, shall, within 90 days, revise and submit its restoration plan to its Reliability Coordinator for approval." Subrequirements, 4.1 and 4.2 can be deleted.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
The EOP-005's purpose is to "[e]nsure plans, Facilities, and personnel are prepared to enable System restoration from Blackstart Resources to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection." Similarly, EOP-006's purpose is to "[e]nsure plans are established and personnel are prepared to enable effective coordination of the System restoration process to ensure reliability is maintained during restoration and priority is placed on restoring the Interconnection." Simply put, the EOP Standards at issue in this project exist to ensure that personnel have clear, effective understanding of the System restoration process, that understanding is shared between TOPs and RCs through coordination and situational awareness, and priority is placed on such efforts. This is a critical reliability task. In light of this importance of these Standards to restoring grid operations, Texas RE continues to be concerned that the proposed changes to these Standards could result in confusion in implementing restoration plans, undermining their stated goals. Simply put, the proposed Standards, as currently drafted, presents a real risk that TOPs and RCs will not have single, clear restoration plans that both entities fully understand during the restoration process and will, therefore, not be able to effectively coordinate restoration efforts. This constitutes a significant reliability issue that the SDT must address in this process.	

Texas RE has identified two significant areas in the proposed EOP-005 Standard in particular that could result in confusion in the ultimate implementation of restoration plans.

First, as Texas RE noted previously, the SDT proposes to require TOPs to update and submit revised restoration plans to their RCs when there is modification “that would change the ability to implement” the restoration plan (EOP-005-3, Requirement R4). Although, Texas RE does not necessarily object to the SDT’s stated intent to require formal updates requiring RC approval solely for material changes, the requirement to update a plan and obtain such an approval should not hinge upon the entity’s perception of its corresponding “ability” to implement the plan. That is to say, a material modification to the restoration plan should require submission of an updated plan regardless of whether the TOP believes the modification will or will not affect its ability to actually implement the existing restoration plan. This is particularly critical because EOP-005-3, Requirement R4 also serves the reliability goal of ensuring RCs have awareness regarding the steps TOPs will take in the restoration process. As such, even if a TOP believes it can still implement its current plan, providing information regarding modifications to the restoration plan still serves the reliability goal of enhancing RC situations awareness.

In addition, Texas RE is concerned that Requirement R4 does not capture the fact that both planned and unplanned permanent BES modifications are subject to RC approval requirements per EOP-006. Texas RE recommends changing the R4 parent requirement to: "Each TOP shall update and submit its revised restoration to its Reliability Coordinator for approval in accordance with EOP-006.” This would indicate EOP-006 approval requirements apply to both 4.1 and 4.2.

If the SDT wishes to capture a materiality threshold for required updates and submissions, Texas RE recommends the SDT focus on the materiality of the change itself. Accordingly, the SDT could revise the proposed Requirement R4 language to simply require submission of an update “to reflect system modifications that would materially change the implementation of its restoration plan.” Texas RE further recommends that the SDT include language requiring summaries of non-material revisions to the plan be at least provided to the RC through a streamlined information sharing process. As such, the SDT should also include language in R3 along the following lines: “Each Transmission Operator shall submit summaries of any immaterial revisions to its restoration plan to its Reliability Coordinator within 45 days of such immaterial changes. For such immaterial changes, no approval by the Reliability Coordinator shall be necessary.” Such language will facilitate effective communication between the TOP and the RC, which is critical to ultimately ensure personnel are prepared to enable System restoration and reliability is maintained throughout the process, while retaining a more streamlined approach for smaller changes.

Second, Texas RE remains concerned EOP-005 has no requirement for TOPs to correct plans not approved by the RC. There appears to be issues if an RC does not approve the plan within 30 calendar days of planned System modifications (or 90 days for unplanned). The modifications may be complete but the plan that includes the modifications may not be approved so an old copy (that cannot be utilized) will be in the Control Centers of a TOP. Texas RE recommends adding language regarding correcting unapproved plans as well as what a TOP is to do if an RC is late with its approval.

The purpose of EOP-005 is to have a clear, understood restoration process. While Texas RE appreciates the SDT’s efforts, the SDT should address areas in which the proposed Standard could result in overlapping, conflicting, or multiple versions of restoration plans.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No
Document Name	
Comment	

We suggest changing the proposed R4 from:

R4 Each TOP shall update and submit its revised restoration plan to its RC for approval when the revision would change its ability to implement its restoration plan as follows:

4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification subject to the RC approval requirements per EOP-006

First of all, the revision doesn't affect your ability to implement the Restoration Plan, it is the Plan. We think what the SDT really means here is you have experienced some change that impacts your ability to implement the approved Plan, and therefore you have to make a revision.

Second, as written, this only addresses a change that you would make due to a BES modification. What if the revision is due to a procedural/organizational change?

We think a better wording would be something like:

R4. Each TOP shall update and resubmit its restoration plan to its RC for review and approval, when a System modification or other change has or will occur which invalidates or makes the approved plan unable to be implemented. Such updates shall be made as follows:

4.1 Within 90 calendar days after identifying any unplanned permanent BES modifications.

4.2 Prior to implementing a planned permanent BES modification or procedural change subject to the RC approval requirements per EOP-006.

Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	

(1) We thank the SDT for attempting to develop a requirement that would apply to TOPs, but only after the identification of a substantive change that impacts the TOP's ability to implement its restoration plan or impact the RC's ability to monitor and direct restoration efforts.

(2) We find the proposed Requirement R4 is confusing regarding when a TOP is required to revise its system restoration plan, particularly since a revision appears to be tied solely to a BES modification. This could be a significant burden for entities to track. We believe the requirement should clarify upfront its application to a selective set of TOPs, and only under certain conditions identified by the SDT. We propose the following language

instead, “Each Transmission Operator, who identifies a change in its restoration plan that would affect its ability to implement its plan or its Reliability Coordinator’s ability to monitor and direct restoration efforts, shall revise and submit its restoration plan to its Reliability Coordinator for approval.”

(3) We have concerns with the SDT’s proposal for Part 4.2, particularly to a general reference to the EOP-006 System Restoration Coordination Standard, and not a specific revision to the standard. We feel this standard could easily become unbundled or change in the future.

(4) Moreover, could the RC or other NERC functional entities have an opportunity to influence a planned permanent BES modification other than through the System Restoration Coordination Standard, such as with a retirement of a large generator or introduction of a RAS?

(5) Furthermore, we ask the SDT to clarify the exact moment just “prior to implementing a planned permanent BES modification.” Is it just before the modification is permanently and electrically connected or disconnected from the System, or during its construction phase when the availability of other existing Facilities are affected?

(6) Likewise, the SDT has assumed that a TOP will revise its restoration plan only under anticipated BES modifications. We believe other reasons could exist, such as for information or operational technology infrastructure modifications or organizational restructuring, which could impact its ability to implement its plan. Hence, we proposed the following language for Part 4.2 instead, “Within 90 calendar days of identifying a change that would affect its ability to implement its plan or its Reliability Coordinator’s ability to monitor and direct restoration efforts.”

Likes 0	
Dislikes 0	

Response

Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF

Answer	Yes
Document Name	

Comment

PJM’s concern with Requirement R6 as written is that it can and has been interpreted to require that every step of the restoration process must be validated through steady state and dynamic simulation, which can be an overly burdensome task. This interpretation may result in thousands of simulations having to be performed and is beyond the intention of the original EOP-005 drafting team. To eliminate any unintentional misinterpretation of this standard (e.g. to make it clear that full steady state and dynamic simulation of the entire Restoration Plan is not required) and to ensure that the right studies and testing are performed to ensure a reliable plan without overly burdening staff, PJM recommends the inclusion of the following language to the requirement:

“R6 Each Transmission Operator shall verify through analysis of actual events, a combination of steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed every five years at a minimum. Such analysis, simulations or testing shall verify”

Likes 1	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	Yes

Document Name	
Comment	

AZPS agrees with requirement R4 and offers the following suggested wording for the proposed standard to enhance clarity:

Each Transmission Operator shall update and submit **its revised restoration plan** to its Reliability Coordinator for approval**, when it has identified planned or unplanned permanent BES modifications that meet the below criteria and would adversely impact its ability to implement** its current, approved restoration plan, as follows:

Likes 0	
Dislikes 0	
Response	
Kerry LaCoste - U.S. Bureau of Reclamation - 1,5 - WECC	
Answer	Yes
Document Name	
Comment	

Although the Rationale for Requirement R4 explains the qualification criteria for a BES modification, when the Rationale section is removed from the EOP-005-3 standard, Reclamation respectfully suggests a footnote be added to R4.4.1 to clarify a BES modification.

Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Sykes - Southern Company - Southern Company Generation and Energy Marketing - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with the revisions and clarifications made by the EOP SDT, based on industry comments, to revise the language "at least once each 15 calendar months" back to "annual" or "annually," as drafted in EOP-005-02? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

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

Answer	No
Document Name	

Comment

We believe there could be some obligation changes between EOP-005-3 and EOP-006-3 regarding the timing of review of restoration plans and submission to the RC. The proposed EOP-005-3 seems to dictate how long a TOP can take between reviews of its plan, but that review must be done according to a schedule agreed to with the RC (EOP-006-3 R5). It may be an improvement to move the timing requirements to the RC side of this obligation and add the 'outer bounds' of the review timing to the RC requirement. Then EOP-005-3 R3 could simply remove the word annually and refer only to the 'agreed upon schedule' with the RC. Also, the clear, unambiguous language regarding the 15 month outer bound on review, does not preclude an 'annual' review.

The proposed R5 of EOP-006-3 would read:

R5. Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area, on a mutually agreed, pre-determined schedule not to exceed 15 calendar months.

The proposed R3 of EOP-005-3 would read:

R3. Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator on a mutually-agreed, predetermined schedule.

Based on Operations Training programs, we support the change to "annual" in R8. There is no need to arbitrarily limit the length of time to 15 calendar months.

We disagree with the change in R9 and R15 of EOP-005-3 of requiring training within 24 calendar months rather than 'every two years'. We feel two calendar years provides more flexibility to match up training schedules and equipment availability. We are not simply looking for more time, just looking for flexibility to match schedules.

Any corresponding changes to annual, 24 calendar months, or 15 calendar months need to be reflect in the VRF/VSL tables as well.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Texas RE supports retention of the 15 calendar month requirement and opposes the change back to “annual” or “annually.” Under the interpretation language cited by the SDT, this change would permit TOPs to delay the review and submit restoration plans for almost two calendar years. Again, EOP-005’s stated purpose is to “ensure plans, Facilities and personnel are prepared to enable System restoration.” Consistent with this principle, a clear 15-month requirement to review and submit restoration plans appears to advance the stated goal of ensuring preparedness to enable System restoration. At a minimum, Texas RE requests that the SDT provide a reliability-based reason for retaining the “annual” submission requirement as opposed to the previously proposed 15-month requirement.

Likes 0	
Dislikes 0	

Response

sean erickson - Western Area Power Administration - 1

Answer	No
Document Name	

Comment

For Compliance concerns "Annual" is not a defined term. At least once every 15 months is clear.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

We believe there could be some obligation changes between EOP-005-3 and EOP-006-3 regarding the timing of review of restoration plans and submission to the RC. The proposed EOP-005-3 seems to dictate how long a TOP can take between reviews of its plan, but that review must be done according to a schedule agreed to with the RC (EOP-006-3 R5). It may be an improvement to move the timing requirements to the RC side of this obligation and add the ‘outer bounds’ of the review timing to the RC requirement. Then EOP-005-3 R3 could simply remove the word annually and refer only to the ‘agreed upon schedule’ with the RC. Also, the clear, unambiguous language regarding the 15 month outer bound on review, does not preclude an ‘annual’ review.

The proposed R5 of EOP-006-3 would read:

R5. Each Reliability Coordinator shall review the restoration plans required by EOP-005 of the Transmission Operators within its Reliability Coordinator Area, on a mutually agreed, pre-determined schedule not to exceed 15 calendar months.

The proposed R3 of EOP-005-3 would read:

R3. Each Transmission Operator shall review its restoration plan and submit it to its Reliability Coordinator on a mutually-agreed, predetermined schedule. Based on Operations Training programs, we support the change to "annual" in R8. There is no need to arbitrarily limit the length of time to 15 calendar months. We disagree with the change in R9 and R15 of EOP-005-3 of requiring training within 24 calendar months rather than 'every two years'. We feel two calendar years provides more flexibility to match up training schedules and equipment availability which is challenging, especially when personnel are dispersed over a wide multi-state area as it is in our case. Any corresponding changes to annual, 24 calendar months, or 15 calendar months need to be reflect in the VRF/VSL tables as well.	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	No
Document Name	
Comment	
If the language is changed to "annual"; "Annual" needs to be defined and included in the NERC Glossary of Terms.	
Likes 0	
Dislikes 0	
Response	
Kerry LaCoste - U.S. Bureau of Reclamation - 1,5 - WECC	
Answer	No
Document Name	
Comment	
Reclamation is aware that some EROs believe that the term "annual" may be misinterpreted by Responsible Entites such that a Responsible Entity would allege compliance if the "annual" review took place once in 2015 and once in 2016, albeit January 2015 and December 2016, thereby resulting in potentially bi-annual reviews. Although the NERC CAN-0010, Revised 11-16-11, provided instructions to the Compliance Enforcement Authority on how to assess compliance when a standard requires an "annual" activity, Reclamation believes a more defined time frame in the Standard is beneficial to reduce a Registered Entity's potential confusion and compliance violations. Therefore, Reclamation recommends the language "at least once ***every*** 15 calendar months" be retained.	
Likes 0	

Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 6	
Answer	No
Document Name	
Comment	

The standards are a minimum that must be met in order to be compliant. There is nothing in the standards saying an entity cannot do something, such as in this case a review, more often. The standard if left alone clearly states "at least once every 15 calendar months", which can mean:

- the review can be completed on January 1, 2016 and then again on March 29, 2017;
- or it could mean once on January 1, 2016 and again on January 1, 2017;
- or on January 1, 2016 then again on February 1, 2016, then again on March 1, 2016, then etc. etc.

LES believes the entities that commented asking for the change back to "annual" are misunderstanding the intent of "at least once each 15 calendar months". By changing the language to "annual" you are creating several issues:

- misinterpretation of the word "annual" as it is not a NERC Glossary Term
- reliance on a Compliance Application Notices (CANs) which are not industry approved or enforceable
- an unnecessary burden on entities as it tightens the timeline for reviews
- the term "annual" has been removed from multiple standards in favor of "at least once each 15 calendar months"

If the language is changed to "annual"; "Annual" needs to be defined and included in the NERC Glossary of Terms, however, this is in contradiction to other standards moving away from the term annual (i.e. CIP V5)

Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	

We appreciate the SDT's efforts to move back to using annual references within the standard. We also applaud the SDT for not attempting to define the meaning of "annual" within this standard. Industry has adapted its processes to align with the current language, and we feel modifying such processes could cause confusion for both operations and compliance.	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
IPC agrees with changing the language back to "Annual/Annually". However, the term Annual should be defined or point to where it is defined. Is annual 11–13 months? Or is it calendar year? If it is calendar year, there is some concern around what happens if an operator is trained each year, but the time between training is well over 12 months. For example, training occurs in March of 2017 and then the next training is December of 2018. This would be 21 months apart, but training was completed each year.	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Xcel Energy strongly agrees with the change back to "annual" (per our comments to the previous revision), but questions the change in R9 and R15 from "every two calendar years" to "every 24 calendar months". We feel this is the same issue previously raised with the "annual" language and question why the SDT, in the same revision where they went back on the previous change to "annual", would at the same time change this language to apply in a way that is not consistent with the "annual" requirements. Xcel Energy recommends reverting to "every two calendar years".	
Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Pusztai - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Lori Folkman, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Sykes - Southern Company - Southern Company Generation and Energy Marketing - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 1	Nick Braden, N/A, Braden Nick
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	

3. Do you agree with the revisions and clarifications made by the EOP SDT to standard EOP-006-2? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
In EOP-006-3, Draft #2, R1.2, SOCO does not agree with the removal of the word “adjacent”. The TOP should only have to document in the restoration plan the process to interconnect with ADJACENT TOPs and not TOPs in general.	
Likes 0	
Dislikes 0	
Response	
Jennifer Sykes - Southern Company - Southern Company Generation and Energy Marketing - 6	
Answer	No
Document Name	
Comment	
In EOP-006-3, Draft #2, R1.2, SOCO does not agree with the removal of the word “adjacent”. The TOP should only have to document in the restoration plan the process to interconnect with ADJACENT TOPs and not TOPs in general.	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 5	
Answer	No
Document Name	
Comment	
Comments: Part 1.2 should at least have the word “other” inserted befor the last use of Reliability Coordinators. In R3, 13 calendar months should be annually to match the changes made in EOP-005. The rolling monthly requirements are difficult to track and provide no real value over the calendar year requirement. In R8, 24 calendar months should remain two calendar years. The rolling monthly requirements are difficult to track and provide no real value over the	

calendar year requirement.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

R 1.2 should have the word “other” inserted befor the last use of Reliability Coordinators.

In R3, 13 calendar months should be annually to match the changes made in EOP-005. The rolling monthly requirements are difficult to track and provide no real value over the calendar year requirement.

In R8, 24 calendar months should remain two calendar years. The rolling monthly requirements are difficult to track and provide no real value over the calendar year requirement

Likes 0	
Dislikes 0	

Response

Eric Ruskamp - Lincoln Electric System - 6

Answer	No
Document Name	

Comment

1. LES believes R3 should be changed to “at least once every 15 calendar months” to match EOP-005. The RC timeline and the TOP timeline should not be different.
2. LES agrees with R7, however ‘annual’ could be better stated as “at least once each calendar year”. LES believes all training should be done on an annual (calendar year basis).
3. LES believes every two calendar years is much easier to track than 24 calendar months, since that makes it rolling.

Likes 0	
Dislikes 0	

Response

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

Answer	No

Document Name	
Comment	
Duke Energy recommends that the drafting team consider changing the calendar month language used throughout the standard. We believe that use of the term “annual” or “annually” throughout the standard is necessary, and not just in R7.	
Likes 0	
Dislikes 0	
Response	
Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	No
Document Name	
Comment	
See Southern Company and GSOC comments.	
Likes 0	
Dislikes 0	
Response	
Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	No
Document Name	
Comment	
See GSOC and Southern Company comments.	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	No
Document Name	
Comment	

R 1.2 should have the word “other” inserted befor the last use of Reliability Coordinators.

Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
We disagree with the removal of the approved R8 that requires the RC to provide authorization before resynchronizing islands. We feel this is an important reliability concept that should not have been removed and should be reinstated in the drafts. By not specifically requiring RC authorization before resynchronizing islands, islands could be synched or sync attempted resulting in threats to the fledgling restoration. We also disagree with the removal of “adjacent” in the proposed R1.2. If adjacent is left out, then there needs to be a clarification of which RCs and/or TOPs are necessary to be coordinated with. As currently stated it is not clear which RCs need to have interconnection criteria with each other and could lead to an interpretation that ALL RC’s should coordinate when that is unnecessary for reliability. We understand the intent of the requirement to require coordination only with only neighboring RCs. We prefer the word “adjacent” be included there as this provides the needed clarity.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
15 months, 13 months, or annual is inconsistent. Choose one time frame and be consistent.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	No

Document Name	
Comment	

We also continue to disagree with the removal of the approved R8 that requires the RC to provide authorization before resynchronizing islands. We feel this is an important reliability concept that should not have been removed and should be reinstated in the drafts. By not specifically requiring RC authorization before resynchronizing islands, islands could be synched or sync attempted resulting in threats to the fledgling restoration.

We also disagree with the removal of "adjacent" in the proposed R1.2. If adjacent is left out, then there needs to be a clarification of which RCs and/or TOPs are necessary to be coordinated with. As currently stated it is not clear which RCs need to have interconnection criteria with each other and could lead to an interpretation that ALL RC's should coordinate when that is unnecessary for reliability. We understand the intent of the requirement to require coordination only with only neighboring RCs. We prefer the word "adjacent" be included there as this provides the needed clarity.

Likes 0	
Dislikes 0	
Response	

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	No
Document Name	
Comment	

We believe the SDT should use its authority, as outlined within this project's SAR, to review Requirement R7 as a training-related requirement whose retirement is based on Paragraph 81, B7 Redundant criteria. Many aspects of this training requirement are already incorporated within a RC's systematic approach to training program, as required within various PER standards. At the very least, we ask the SDT to remove the reference to annual training and instead focus the requirement on training topics that should be included in an operations training program. This similar approach was taken by the 2007-06.2 Phase 2 of System Protection Coordination SDT with the introduction of NERC Reliability Standard PER-006-1.

Likes 0	
Dislikes 0	
Response	

Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	
Comment	

ERCOT appreciates the efforts to clarify the issue of interpretation on the words "neigbboring" and "adjacent." However, the term "'neighboring' in no ways gives the RC the latitude to define which applicable entities are to be included in its restoration plan, since this term could be interpreted either way by entities and auditors allike until a NERC project or NERC SDT defines the meaning of "neighboring" or "adjacent" in reference to the ERCOT interconnection. ERCOT would prefer specificity on what this means, rather than leaving it unclear, given the duty to coordinate if we are "neighboring." ERCOT asks the SDT to clarify the meaning of the words "adjacent" or "neigboring" and provides this example:

1. Each Reliability Coordinator shall develop, and implement a Reliability Coordinator Area restoration plan. The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring ***(i.e., within the same interconnection)*** Reliability Coordinators, or an energized island has been formed on the BES within the Reliability Coordinator Area. The scope of the Reliability Coordinator's restoration plan ends when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas. The restoration plan shall include:..."

Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 1	Nick Braden, N/A, Braden Nick
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kerry LaCoste - U.S. Bureau of Reclamation - 1,5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Lori Folkman, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1,	

5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE is concerned there is no requirement for the Reliability Coordinator to provide its restoration plan to Transmission Operators outside the Reliability Coordinator Area. There is also no requirement for a Transmission Operator to provide its restoration plan with a Reliability Coordinator that is not its own contained within EOP-005.) If there is criteria required to re-establish interconnections with other TOPs in other Reliability Coordinator Areas, it is prudent to provide the restoration plan to those TOPs. Simply providing the restoration plan to the neighboring RC does not mean the TOP (in the neighboring RC Area) will be aware as the neighboring RC is under no obligation to provide that specific plan to its TOPS.

Texas RE noticed there is a different time period between the Reliability Coordinator and the Transmission Operators to review their restoration plans. EOP-005-2 Requirement, R3 which requires Transmission Operators to review and submit its restoration plan annually while EOP-006-3, R3 requires the Reliability Coordinator to review its plan within 13 calendar months. Texas RE is concerned the two plans may not be coordinated if they are reviewed (and potentially revised) at different times.

In addition, Texas RE respectfully requests rationale as to why EOP-006-3 Requirement R3 changed the review to within 13 months from 15 months.

Likes 0	
Dislikes 0	

Response

4. Do you agree with the revisions and clarifications made by the EOP SDT, based on industry comments, to revise the language "at least once each 15 calendar months" back to "annual" or "annually," as drafted in EOP-006-02? If you do not agree, or if you agree but have comments or suggestions for the proposed standard, please provide your recommendation and explanation.

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE supports retention of the 15 calendar month requirement and opposes the change back to "annual" or "annually." Texas RE is concerned CAN-010 could allow for training on critical tasks to take place almost two years apart.	
Likes 0	
Dislikes 0	
Response	
sean erickson - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
15 months, 13 months, or annual is inconsistent. Choose one time frame and be consistent.	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	No
Document Name	
Comment	
Incorporate this throughout EOP-006 requirements. It has not been consistently changed back to "annual" or "annually". If the language is changed to "annual"; "Annual" needs to be defined and included in the NERC Glossary of Terms.	
Likes 0	
Dislikes 0	

Response	
Kerry LaCoste - U.S. Bureau of Reclamation - 1,5 - WECC	
Answer	No
Document Name	
Comment	
Reclamation is aware that some EROs believe that the term "annual" may be misinterpreted by Responsible Entites such that a Responsible Entity would allege compliance if the "annual" review took place once in 2015 and once in 2016, albeit January 2015 and December 2016, thereby resulting in potentially bi-annual reviews. Although the NERC CAN-0010, Revised 11-16-11, provided instructions to the Compliance Enforcement Authority on how to assess compliance when a standard requires an "annual" activity, Reclamation believes a more defined time frame in the Standard is beneficial to reduce a Registered Entity's potential confusion and compliance violations. Therefore, Reclamation recommends the language "at least once ***every*** 15 calendar months" be retained.	
Likes 0	
Dislikes 0	
Response	
Eric Ruskamp - Lincoln Electric System - 6	
Answer	No
Document Name	
Comment	
LES believes training should be required either every calendar year or every other calendar year, but disagrees with changing the wording to "annual" in R7 as it is too ambiguous. LES also disagrees with changing EOP-006 R3 (for reviewing restoration plan) from "within 15 calendar months" to "within 13 calendar months" too.	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	Yes
Document Name	
Comment	
We appreciate the SDT's efforts to move back to using annual references within the standard. We also applaud the SDT for not attempting to define the meaning of "annual" within this standard. Industry has adapted its processes to align with the current language, and we feel modifying such processes	

could cause confusion for both operations and compliance.	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Clarify definition of Annual. (See question 2 response.)	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Duke Energy agrees with the proposed change referenced in the question, but suggests the drafting team consider using the terms “annual” or “annually” in all pertinent areas throughout the standard.	
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Incorporate this throughout EOP-006 requirements. It has not been consistently changed back to “annual” or “annually” as noted in comments above.	

Likes 0	
Dislikes 0	
Response	
Elizabeth Axson - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
M Lee Thomas - Tennessee Valley Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scott Downey - Peak Reliability - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Lori Folkman, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stanley Beasley - Stanley Beasley On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1; - Stanley Beasley	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Preston Walker - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 1,3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Michael Ibold, Xcel Energy, Inc., 5, 3, 1; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jennifer Sykes - Southern Company - Southern Company Generation and Energy Marketing - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marsha Morgan - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Robert Coughlin - Robert Coughlin On Behalf of: Michael Puscas, ISO New England, Inc., 2; - Robert Coughlin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 1	Nick Braden, N/A, Braden Nick
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

5. Please provide any additional comments for the EOP SDT to consider, if desired.

Diana McMahon - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
We would like the SDT to consider separating EOP-005-2 R1 into 2 requirements for a few reasons. The subparts of the requirement are not applicable to the implementation of the plan resulting in a awkwardly worded requirement. The assessment of the plan is critical to the reliability of the BES and the plan should linclude all of the identified parts, but it becomes obscure, secondary even in consideration with the implementation of the plan. Additionally, the EROs within NERC are working to develop an updated violation calculator for consideration when addressing potential violations. Per a recent WECC compliance workshop, the calculator is likely to include the consideration of “Time-Horizon”, which given that R1 has 2, creates confusion.	
Likes 1	Nick Braden, N/A, Braden Nick
Dislikes 0	
Response	
Justin Mosiman - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
Regarding EOP-005-3 R8.5 and R1.9: Bonneville Power Administration (BPA) suggests modifying the applicability of R1.9 and R8.5 to Transmission Operators operating solely as Transmission Operators and not concurrently operating as a Balancing Authority because a transfer does not take place for joint entities.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6	
Answer	
Document Name	
Comment	
Dominion suggests that “the TOP’s ability to implemenet the plan” be struck from the R4 Rationale. Dominion is of the opinion that sentence will be	

clearer without this information and that it more closely mirrors the intention of the Standards Drafting Team.

The sentence should now read: “The intent is not to require a TOP to update and submit changes that do not substantively change the restoration plan or the RCs ability to monitor and direct the restoration efforts.”

Likes 0	
Dislikes 0	

Response

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	
Document Name	

Comment

Based on the draft of RSAW, HQT suggest to add the obligation to submit to the TOP a corrective action plan on the R14 when the TOP testing requirement(s) are not met :

Actual requirement

R14. Each Generator Operator with a Blackstart Resource shall perform Blackstart Resource tests, and maintain records of such testing, in accordance with the testing requirements set by the Transmission Operator to verify that the Blackstart Resource can perform as specified in the restoration plan. *[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]*

14.1. Testing records shall include at a minimum: name of the Blackstart Resource, unit tested, date of the test, duration of the test, time required to start the unit, an indication of any testing requirements not met under Requirement R7.

14.2. Each Generator Operator shall provide the blackstart test results within 30 calendar days following a request from its Reliability Coordinator or Transmission Operator.

Corrective action plan :

14.3 Each Generator Operator shall, within 10 calendar days of an indication of any testing requirements not met under Requirement R7: [*Violation Risk Factor:*

High] [*Time Horizon: Operations Planning, Long*]-*Term Planning*

☐ Develop a Corrective Action Plan (CAP) for the identified Blackstart Resource, and an evaluation of the CAP’s applicability to the entity’s other Blackstart Ressource including other locations; or

☐ Explain in a declaration why corrective actions are beyond the entity's control owould not improve BES reliability, and that no further corrective actions will be taken.

☐Submit the conclusion(s) to the Transmission Operator

Typo from M15 to be corrected in coordination with R15 :

M15 Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup and energizing a bus and synchronization of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement R15.

Likes 0	
Dislikes 0	

Response

Angela Gaines - Portland General Electric Co. - 3, Group Name PGE - Group 1

Answer	
Document Name	

Comment

Although Portland General Electric Company (PGE) voted "affirmative" during this round of balloting, PGE feels strongly that ANY training requirements identified in the development of a standard should be addressed in the PER training standards and not in separate standards and requirements. The Systematic Approach to Training is as such that training requirements from other standards are easily adoptable into the training regimen. Adding requirements outside of the PER standards becomes an administrative nightmare by duplicating efforts relating to tracking and the application of the actual training.

Additionally, similar to the change made in Requirement R8, there is no reason to change Requirement R9 from two calendar years to 24 calendar months. Perhaps it seems like every two calendar years and every 24 calendar months are the same thing but it isn't. By changing the measurement to months, the tracking that is required starts in the month the training is given for any particular individual. Based on the individual schedules the tracking takes on a scattered approach, akin to herding cats. Please seriously consider changing R9 back to every two calendar years.

Likes 0	
Dislikes 0	

Response

Chris Scanlon - Exelon - 1

Answer	
Document Name	

Comment

We find EOP-005 -3 R1 redline changes to be confusing. The requiremnt needs additional clarification or should be restated. Does the requiremnt address real-time or study mode? Consider replacing the comma after "service" with a period and restating the second clause as a seperate sentence.

Likes 0	
Dislikes 0	

Response

Don Schmit - Nebraska Public Power District - 5

Answer	
Document Name	

Comment

In EOP-005 R9, recommend the following language: “Each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider shall provide a minimum of two hours of System restoration training every **two calendar years** to their field switching personnel identified as performing unique tasks associated with the Transmission Operator’s restoration plan that are outside of their normal tasks. **Unique tasks are those tasks that are defined by each Transmission Operator, each applicable Transmission Owner, and each applicable Distribution Provider.”**

In EOP-005 R 9 and R15, 24 calendar months should remain two calendar years. The rolling monthly requirements are difficult to track and provide no real value over the calendar year requirement.

In the first round of comments we provided the comment in regards to Section C1.1.2 Evidence Retention for replacing "last monitoring acitivity" to "last compliance audit".

In the new draft of EOP-005-3 the drafting team did not change the verbiage to “last compliance audit” as they suggested that they would. In fact the Evidence retention section now has the term “last monitoring activity” in an additional four other places under record retention. In addition, evidence retention for R10 states “…since it last monitoring activity as well as one previous monitoring activity period…”. Monitoring activities are Audits, Spot checks and Self Certifications. An etity should not be required to track evidence retention on a moving target. In addition, if a requirement is not audited, spot-checked or self certified, does an entity then need to retain evidence back to the last “monitoring activity” which may have been several years and several audit cycles?

Our suggestion is that the drafting team remove all references to “last monitoring activity” and replace with the proper retention period that is not a moving target; such as last compliance audit, for three calendar years or whatever the appropriate retention period is.

Also in section C.1.1.2 it is noted that there is new wording in four separate places regarding evidence retention for issues of non-compliance. One such statement reads “If a Transmission Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant”. For the underlined portion of this sentence ‘until found compliant’ we would suggest a wording change to some other statement, as a Regional Entity typically does not find anyone “compliant”. One suggestion is “..until the entity is notified that the remedy for non-compliance is complete”.

Likes 0	

Dislikes 0	

Response

Jamison Cawley - Nebraska Public Power District - 1

Answer	
Document Name	

Comment

In the new draft of EOP-005-3 the drafting team did not change the verbiage to “last compliance audit” as they suggested that they would. In fact the Evidence retention section now has the term “last monitoring activity” in an additional four other places under record retention. In addition, evidence retention for R10 states “…since it last monitoring activity as well as one previous monitoring activity period…”. Monitoring activities are Audits, Spot checks and Self Certifications. An etity should not be required to track evidence retention on a moving target. In addition, if a requirement is not audited, spot-checked or self certified, does an entity then need to retain evidence back to the last “monitoring activity” which may have been several years and several audit cycles?

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Likes 0	
Dislikes 0	

Response

Jamison Cawley - Nebraska Public Power District - 1

Answer	
Document Name	

Comment

In the new draft of EOP-005-3 the drafting team did not change the verbiage to “last compliance audit” as they suggested that they would. In fact the Evidence retention section now has the term “last monitoring activity” in an additional four other places under record retention. In addition, evidence retention for R10 states “…since it last monitoring activity as well as one previous monitoring activity period…”. Monitoring activities are Audits, Spot checks and Self Certifications. An etity should not be required to track evidence retention on a moving target. In addition, if a requirement is not audited, spot-checked or self certified, does an entity then need to retain evidence back to the last “monitoring activity” which may have been several years and several audit cycles?

Our suggestion is that the drafting team remove all references to “last monitoring activity” and replace with the proper retention period that is not a moving target; such as last compliance audit, for three calendar years or whatever the appropriate retention period is.

Also in section C.1.1.2 it is noted that there is new wording in four separate places regarding evidence retention for issues of non-compliance. One such statement reads “If a Transmission Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant”. For the underlined portion of this sentence ‘until found compliant’ we would suggest a wording change to some other statement, as a Regional Entity typically does not find anyone “compliant”. One suggestion is “..until the entity is notified that the remedy for non-compliance is complete”.

Likes 0	
Dislikes 0	

Response

Anthony Jablonski - ReliabilityFirst - 10

Answer	
Document Name	

Comment

RF provides a negative opinion for the EOP-005-3 VSLs and offers the following comments:

1. VSL for R1 –
    i. RF notes the SDT had updated the Severe VSL for Requirement R1 but still believes there is a gap. For example, as modified it now states “…but failed to implement the applicable requirement parts within Requirement R1.” Since all sub-parts under Requirement R1 are applicable, this new language is basically stating the entity failed to implement all nine sub-parts. Once again there is a gap when an entity fails to meet between four and eight sub-parts. RF suggest the following as an additional “OR” VSL to the Severe VSL to address our concern.
        a. The Transmission Operator has an approved plan but failed to comply with four or more of the requirement parts within Requirement R1.
2. VSL for R8 –
    i. In the consideration of comments report, the SDT responded: “The EOP SDT reviewed your comment and made conforming changes.” When RF reviews the new redline version, there are no changes shown for the VSLs for R8. RF understands Requirement R8 had been modified and had replaced the “15 months” language with “annual”, but this should still be reflected in the VSLs. RF recommends modifying the Severe VSL level as follows:
        a. Severe VSL - The Transmission Operator has not included [annual] System restoration training in its operations training program

RF provides a negative opinion for the EOP-006-3 VSLs and offers the following comments:

1. VSL for R5 –
    i. In the previous comment period, RF noted that since word “notification” is not in Requirement R5, there is subsequently no requirement for notifications. RF suggested removing the second “OR” VSL from each of the VSL Categories. In the consideration of comments the SDT responded: “The EOP SDT reviewed your comments, but agreed that ‘notified’ is in M5; and, therefore, did not make any changes.” RF would like to remind the SDT that the NERC *Violation Severity Level Guidelines* document states: "A Violation Severity

	Level (VSL) is a post-violation measurement of the degree to which a Reliability Standard Requirement was violated (Lower, Moderate, High, or Severe)." As we can see, it references Requirements being violated and not Measures. If the SDT believes notification is an important piece, RF suggests including notifications to the language in Requirement R5. Absent including notification language in Requirement R5, RF continues to suggest removing the second "OR" VSL from each of the VSL Categories as "notifications" are not required by the Requirement.
Likes 0	
Dislikes 0	
Response	
Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

In EOP-005 R 9 and R15, 24 calendar months should remain two calendar years. The rolling monthly requirements are difficult to track and provide no real value over the calendar year requirement.

In the first round of comments we provided the following comment in regards to Section C1.1.2 Evidence Retention and we are also providing the drafting team response here:

In the new draft of EOP-005-3 the drafting team did not change the verbiage to "last compliance audit" as they suggested that they would. In fact the Evidence retention section now has the term "last monitoring activity" in an additional four other places under record retention. In addition, evidence retention for R10 states "…since it last monitoring activity as well as one previous monitoring activity period…". Monitoring activities are Audits, Spot checks and Self Certifications. An etity should not be required to track evidence retention on a moving target. In addition, if a requirement is not audited, spot-checked or self certified, does an entity then need to retain evidence back to the last "monitoring activity" which may have been several years and several audit cycles?

Our suggestion is that the drafting team remove all references to "last monitoring activity" and replace with the proper retention period that is not a moving target; such as last compliance audit, for three calendar years or whatever the appropriate retention period is.

Also in section C.1.1.2 it is noted that there is new wording in four separate places regarding evidence retention for issues of non-compliance. One such statement reads "If a Transmission Operator is found non-compliant for any requirement, it shall keep information related to the non-compliance until found compliant". For the underlined portion of this sentence 'until found compliant' we would suggest a wording change to some other statement, as a Regional Entity typically does not find anyone "compliant". One suggestion is "..until the entity is notified that the remedy for non-compliance is complete".

Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	

Document Name	
Comment	

IPC does not agree with the new requirement 1.9 of requiring a process to transfer operations back to the Balancing Authority in accordance with RC criteria. Based on NERC definition of Balancing Authority, this function includes "maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time." So, a Balancing Authority function is maintained at all times, even during a System Restoration, so there is no process "to transfer operation back to the BA." The Balancing Authority should be involved in the Restoration of the system from initiation of event to resumption of "Normal Operations." The NERC functional Model describes real-time actions of the Balancing Authority entity to "Implement System Restoration plans as directed by the Transmission Operator."

In R9, maintain calendar year language throughout whole standard.

Likes 0	
Dislikes 0	
Response	

Michael Cruz-Montes - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	
Comment	

CenterPoint Energy appreciates the SDT's continued efforts to incorporate the industry's comments and concerns into the current drafts for EOP-005-3 System Restoration from Blackstart Resources and EOP-006-3 System Restoration Coordination.

Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	
Document Name	
Comment	

AZPS agrees with requirement R1 and offers the following suggested wording for the proposed standard to enhance clarity:

Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator's System **to a state whereby the choice of the next Load to be restored is not driven by the need to control frequency or voltage** following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service...

Likes 0	
Dislikes 0	

Response

Kerry LaCoste - U.S. Bureau of Reclamation - 1,5 - WECC	
Answer	
Document Name	

Comment
Reclamation recommends the following additional change to the existing Draft Standard EOP-005-3, R1, second sentence: Each Transmission Operator shall develop and implement a restoration plan approved by its Reliability Coordinator. The restoration plan shall be implemented to restore the Transmission Operator's System following a Disturbance in which one or more areas of the Bulk Electric System (BES) shuts down and the use of Blackstart Resources is required to restore the shutdown area to service, to a state wherein the choice of the next Load to be restored is not driven by the need to control frequency or voltage regardless of whether the Blackstart resource is located within the Transmission Operator's System. Reclamation recommends replacing "the Reliability Coordinator" with "its Reliability Coordinator" in the following locations: EOP-005-3, Requirements and measures R10, R16, M16, and VSL Table R4, VSL Table R10, and VSL Table R16 to be consistent throughout the Standard.

Likes 0	
Dislikes 0	

Response

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

Comment
In EOP-006-3, R1, the requirement states "The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or **an energized island has been formed on the BES within the Reliability Coordinator Area**." On the other hand the restoration plan ends, "…when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas." If an island was created internal to a TOP around a hydro plant for example, this would fall within the scope of the RC restoration plan to start since it would be an island on the BES within the Reliability Coordinator Area. It would also meet the requirement to end the RC restoration plan because all TOPs and RC Areas would still be interconnected. It is reasonable to assume that the drafting team does not anticipate a Reliability Coordinator implementing their RC restoration plan and then ending their RC restoration plan at the same time. The drafting team should clarify when the RC restoration plan should be implemented such that the Requirement does not conflict with itself. In EOP-005-3, it is very clear the TOP restoration plan begins when a Blackstart Resource is required to restore a shut down area to service. This is different than when the RC restoration plan begins in EOP-006-3. There could be instances where the RC implements their restoration plan but no TOP within that RC implements their restoration plan. It is recommended that the standard drafting team also update EOP-006-3 R1 to better coordinate with

the start and end of the TOP restoration plans.

The RC restoration plan is developed for the RC but it contains criteria that the TOP will need to follow during system restoration. For example, EOP-006 R1.2 sets criteria and conditions for re-establishing interconnections for neighboring TOPs. R1.6 sets criteria for transferring operations and authority back to the Balancing Authority. It could be more clear in EOP-005 that the TOP's restoration plan should be developed in coordination with its Reliability Coordinator's restoration plan. For example, the criteria and conditions for re-establishing interconnections with other Transmission Operator defined in the RC restoration plan according to EOP-006 R1.2 should inform the TOP restoration plan when the TOP is developing language to meet EOP-005 R1.3 procedures for restoring interconnections with other Transmission Operators. We recommend changing the subrequirement R1.1 in EOP-005 to state the TOP restoration plan shall include, “Strategies for system restoration that ***meet the criteria defined in the Reliability Coordinator’s restoration plan and*** are coordinated with the Reliability Coordinator’s high level strategy for restoring the interconnection.”

We recommend that where requirements are removed from the standard (such as in EOP-005-3), that the number for the deleted requirement remain and be notated as “Retired,” “Removed,” or “Intentionally left blank,” so that utilities do not have to perform unnecessary updates of compliance documentation simply for the sake of renumbering requirement references.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Thank you for your time and efforts!

Likes 0	
Dislikes 0	

Response

Joseph Smith - PSEG - Public Service Electric and Gas Co. - 1

Answer	
Document Name	

Comment

I wish to adopt the following PJM comments:

Comments: R6

PJM's concern with this requirement as written is that it can and has been interpreted to require that every step of the restoration process must be validated through steady state and dynamic simulation, which can be an overly burdensome task. This interpretation may result in thousands of simulations having to be performed and is beyond the intention of the original EOP-005 drafting team. To eliminate any unintentional misinterpretation of this standard (e.g. to make it clear that full steady state and dynamic simulation of the entire Restoration Plan is not required) and to ensure that the right studies and testing are performed to ensure a reliable plan without overly burdening staff, PJM recommends the inclusion of the following language to the requirement:

"R6 Each Transmission Operator shall verify through analysis of actual events, a combination of steady state and dynamic simulations, or testing that its restoration plan accomplishes its intended function. This shall be completed every five years at a minimum. Such analysis, simulations or testing shall verify"

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

We appreciate the re-insertion of the language in EOP-005-3 R1 describing the 'end scope' of the TOP Restoration plan. The removal in the first posting created uncertainty as to what the scope of the TOP plan should be. This is a good change and we support the re-inclusion of this language.

We believe the following change to the proposed **R1.9** would provide better clarity as to the intent of the SDT. If the intent is different, we request additional clarity be provided in a response to our comment.

1.9. Operating Processes for transferring operational control back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.

In **R6** of **EOP-005-3**, we are disappointed that further clarity is not given on the scope or breadth of the steady state and dynamic simulation that would be required. Please expand the rationale with more explanation of the SDT's intent of what constitutes an acceptable steady state and dynamic simulation. Perhaps a whitepaper or guidance document could be created out of one of the NERC Technical Committees providing this guidance.

Also in **R8** of the proposed **EOP-005-3**, we suggest adding the phrase 'operational control' in the rationale for R8 to support the link to R1.9. The rationale would be worded as follows:

Rationale for Requirement R8: The addition of Requirement 8, Part 8.5 allows operating personnel to gain experience on all stages of restoration, including coordination needed transferring operational control, to include Demand and resource balance operations, back to the Balancing Authority in accordance with Requirement R1, Part 1.9.

In the proposed **R8.1** of **EOP-006-3**, we would like to see the GOPs identified with the qualifier "as having a defined role in the TOP's restoration plan", rather than leaving it open-ended. As currently stated, any GOP, even without a role in restoration, would be required to participate. The edited language would read:

8.1. Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified as having a defined role in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every 24 calendar months.

In **EOP-006-3, R3**, the SDT references a change to 13 months for consistency with other standards. When providing the response to comments, can you please provide other locations within the approved body of Standards where 13 months is currently stated?

EOP-006-3 R7 is worded in seeming conflict with the M7 language. R7 simply requires the RC to 'include within its training program, annual System restoration training'. However the action verb in the requirement never mentions actually providing the training. The M7 language however seems to indicate needing to provide evidence of 'providing' the training. Either the M7 language or R7 language should be edited to match the SDT's intent.

Likes 0	
Dislikes 0	

Response

Chris Gowder - Chris Gowder On Behalf of: Carol Chinn, Florida Municipal Power Agency, 5, 6, 4, 3; Chris Adkins, City of Leesburg, 3; David Schumann, Florida Municipal Power Agency, 5, 6, 4, 3; Don Cuevas, Beaches Energy Services, 1, 3; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 5, 6, 4, 3; Richard Montgomery, Florida Municipal Power Agency, 5, 6, 4, 3; Thomas Parker, Fort Pierce Utilities Authority, 4, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Chris Gowder, Group Name FMPA

Answer	
Document Name	

Comment

FMPA believes many of the requirements in these standards are administrative in nature and should be considered for retirement. We also believe the revisions being proposed will not improve stakeholder understanding of the requirements or reliability, and may even lead to further confusion. Furthermore, the redlines posted by the drafting team lead reviewers to believe changes are being proposed that are not in fact changes from the current approved versions. A redline comparison to the current approved version should be provided to allow voters to easily understand the revisions being proposed. FMPA suggests leaving the current approved versions in place.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE remains concerned that several substantive elements of those Requirements are not explicitly incorporated into the proposed EOP-005-3 R1 restoration plan implementation requirements. Texas RE has identified two principal areas of concern, and suggests the SDT revise in proposed language in R1 to address these issues.

First, Requirement R7 provides not only that each affected Transmission Operator (TOP) shall implement its restoration plan following a Disturbance, but also that if “the restoration plan cannot be executed as expected the [TOP] shall utilize its restoration strategies to facilitate restoration.” As presently drafted, there is no explicit requirement in the revised Requirement R1 requiring TOPs to employ such restoration strategies in implementing their restoration plan if the primary processes and procedures specified in the document cannot be executed. This adaptive capability serves an important function and promotes TOPs continuing to maintain situational awareness and strategic reactions throughout the course of restoration activities. As such, Texas RE recommends that if the SDT wishes to retire Requirement R7, it include the following language in the restoration plan content requirements specified in Requirement R1 in order to address this issue:

1.10 Strategies to facilitate restoration if the other elements of the restoration plan cannot be executed as expected.

Second, Requirement R8 presently provides an explicit requirement that TOPs “resynchronize area(s) with neighboring [TOPs] only with the authorization of the Reliability Coordinator or in accordance with established procedures of the Reliability Coordinator.” Although it is perhaps possible to read R1.1’s mandate that the restoration plan include “[s]trategies for system restoration that are coordinated with the [RC’s] high level strategy for restoring the interconnection” as encompassing this requirement, it is not clear that resynchronization is included within either “system restoration strategies” or the RC’s “high level strategy.” Moreover, there is no explicit reference to coordination activities with neighboring TOPs elsewhere in the Standard. To clarify this issue and ensure coordination activities are adequately addressed in entity restoration plans, Texas RE recommends that if the SDT wishes to retire R8, it include the following language in the restoration plan content requirements specified in R1 to address this issues:

1.11 Procedures to resynchronize area(s) with neighboring Transmission Operator area(s) after obtaining authorization from the Reliability Coordinator or in accordance with the established procedures of the Reliability Coordinator..

Texas RE also notes that several substantive elements are also not explicitly incorporated into the proposed EOP-006-3 Requirement R1 restoration plan implementation requirements. Specifically, Requirement R7 provides not only that each affected RC shall implement its restoration plan following a Disturbance, but also that if “the restoration plan cannot be executed as expected the [RC] shall utilize its restoration strategies to facilitate restoration.” As Texas RE indicated above, there is no explicit requirement in the revised EOP-006-3, Requirement R1 requiring RCs to employ such restoration strategies in implementing their restoration plan if the primary processes and procedures specified in the document cannot be executed. Although important for TOPs, these forms of adaptive strategies are particularly critical for RCs given their wide-area view of the BES and overall role in coordinating effective responses to Disturbances. As such, Texas RE recommends incorporating the following language into EOP-006-3, Requirement R1 if the SDT concludes the full retirement of EOP-006-3, Requirement R7 is appropriate:

1.7 Strategies to facilitate restoration if the other elements of the restoration plan cannot be executed as expected.

In a similar vein, EOP-006-3, Requirement R8 presently requires the RC to “coordinate and authorize resynchronizing islanded areas that bridge boundaries between [TOPs] or [RCs]. If the resynchronization cannot be completed as expected the [RC] shall utilize its restoration plan strategies to facilitate resynchronization.” Similar to EOP-005-3, Requirement R1, these elements of R8 are not explicitly included within the various required parts of the RC’s restoration plan as specified in EOP-006-3, R1.1 to 1.6. As a result, there could be confusion regarding resynchronization coordination and authorization obligations, as well as a gap regarding requirements to implement strategies to address resynchronization issues if events occur differently than specified with the RC’s existing restoration plan. Again, Texas RE recommends that if the SDT opts to retire EOP-006-3, Requirement

R8, it incorporate the RC's existing resynchronization obligations explicitly into the required restoration plan elements specified in Requirement R1 by added the following:

1.8 Procedures for coordinating and/or authorizing the resynchronization of islanded areas that bridge the boundaries between Transmission Operators and Reliability Coordinators

Texas RE identified several other areas for improvement:

- Texas RE requests the SDT provide a reason for removing the phrase "for each step of the restoration" from the rationale for EOP-005-3 Requirement R6.

- Texas RE disagrees with use of the term "unique tasks" in EOP-005-3 Requirement 9. That could cause confusion since it is undefined. Texas RE recommends using the term "restoration tasks" instead to indicate these are tasks are specific to restoration.

- Texas RE recommends the VSL for EOP-006-3 Requirement R8 include the piece about requesting the each Transmission Operator and Generator Operator identified in the restoration plan to participate in Reliability Coordinator drills per 8.1. While the VSLs address that the RC should conduct a drill, it does not reference who should participate.

- Texas RE respectfully requests the SDT provide a basis for its decision to adopt a 12-month implementation plan for both EOP-005-3 and EOP-006-3, including any data it considered in determining that this was an appropriate window for affected entities to meet their compliance obligations under the revised Standards.

-

As suggested before, Texas RE recommends there be a project to define and distinguish the terms "neighboring" and "adjacent". Texas RE noticed the mapping document states "The term "neighboring" should be interpreted as "adjacent" and no further clarification is necessary." Texas RE does believe further clarification is necessary as these terms appear throughout Standards and are undefined.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

We appreciate the re-insertion of the language in EOP-005-3 R1 describing the 'end scope' of the TOP Restoration plan. The removal in the first posting created uncertainty as to what the scope of the TOP plan should be. This is a good change and we support the re-inclusion of this language.

We have discussed and believe the following change to the proposed R1.9 would provide some better clarity as to the intent of the SDT. If the intent is different, we request some additional clarity be provided in a response to our comment. Thank you.

1.9. Operating Processes for transferring operationsal control back to the Balancing Authority in accordance with the Reliability Coordinator's criteria.

Also in R8 of the proposed EOP-005-3, we suggest adding the phrase 'operational control' in the rationale for R8 to support the link to R1.9. The rationale would be worded as follows:

Rationale for Requirement R8: The addition of Requirement 8, Part 8.5 allows operating personnel to gain experience on all stages of restoration, including coordination needed transferring operational control, to include Demand and resource balance operations, back to the Balancing Authority in accordance with Requirement R1, Part 1.9.

In the proposed **R8.1** of **EOP-006-3**, we would like to see the GOPs identified with the qualifier "as having a defined role in the TOP's restoration plan", rather than leaving it open-ended. As currently stated, any GOP, even without a role in restoration, would be required to participate. The edited language would read:

8.1. Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified as having a defined role in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least once every 24 calendar months.

In **R6** of **EOP-005-3**, we are disappointed that further clarity is not given on the scope or breadth of the steady state and dynamic simulation that would be required. Please expand the rationale with more explanation of the SDT's intent of what constitutes an acceptable steady state and dynamic simulation. Perhaps a whitepaper or guidance document could be created out of one of the NERC Technical Committees providing this guidance.

In **EOP-006-3, R3**, the SDT references a change to 13 months for consistency with other standards. When providing the response to comments, can you please provide other locations within the approved body of Standards where 13 months is currently stated?

EOP-006-3 R7 is worded in seeming conflict with the M7 language. R7 simply requires the RC to 'include within its traingin program, annual System restoration training'. However the action verb in the requirement never mentions actually providing the training. The M7 language however seems to indicate needing to provide evidence of 'providing' the training. Either the M7 language or R7 language should be edited to match the SDT's intent.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	
Document Name	

Comment

(1) We thank the SDT for listening to our previously submitted comments, specifically the removal of "maintain" from requirement language and incorporation of "annual" within appropriate requirements.

(2) However, we question the language listed within Requirement R1 of EOP-005-1. We question if the SDT meant to remove "to service" from the

phrase "…required to restore the shutdown area to service," before adding the proposed language "to a state whereby the choice of the next Load to be restored is not driven…" We recommend removing the "to service" reference from the requirement to alleviate confusion.

(3) We caution the SDT on its capitalization of "Load" in Requirement R1 of EOP-005-1. According to the NERC Glossary of Terms, the definition refers to an "end-use device or customer that receives power from the electric system." While a TOP who is part of a vertically integrated utility may have the ability to choose which end-use customers it can restore and in what order, other utility business models rely on BAs and DPs to select pre-defined load block quantities as part of its restoration strategy. We recommend that the term "load" should not be capitalized in this context.

(4) We believe the SDT should use its authority, as outlined within this project's SAR, to review Requirement R8 as a training-related requirement whose retirement is based on Paragraph 81, B7 Redundant criteria. Many aspects of this training requirement are already incorporated within a TOP's systematic approach to training program, as required within various PER standards. At the very least, we ask the SDT to remove the reference to annual training and instead focus the requirement on training topics that should be included in an operations training program. This similar approach was taken by the 2007-06.2 Phase 2 of System Protection Coordination SDT with the introduction of NERC Reliability Standard PER-006-1.

(5) We believe the wording with Part 8.5 of EOP-005-3 needs to be clarified. The assumption is the TOP will transfer Demand and resource balance operations within its Transmission Operator Area over to the Balancing Authority. However, there could exist multiple BAs within the TOP's Area. Even the NERC Glossary definition for a BA identifies that a BA can only maintain Demand and resource balance within its own Balancing Authority Area. We believe the language should be clarified to read "Transition of Demand and resource balance to an affected Balancing Authority."

(6) We find the Section C.1.2 of the EOP-005-3 standard confusing with references to "last monitoring activity." We believe the SDT should revise the entire section and replicate the language listed in an already approved standard, like EOP-004-3. Within that specific standard, the Responsible Entity retains evidence of compliance since the last compliance audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

(7) We disagree with the SDT's assessment that the VSLs for R10 and R16 "meet or exceed the current level of compliance." We believe the VSLs for these requirements should be structured according to a percentage of the applicable personnel who need to be trained. This is a similar concept as used for defining the VSLs for R15.

(8) We thank the SDT for this opportunity to provide comments on these standards.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,10 - NPCC, Group Name RSC no Dominion

Answer	
Document Name	

Comment

Based on the draft of RSAW, we suggest to add the obligation to submit to the TOP a corrective action plan on the R14 when the TOP testing requirement(s) are not met :

Actual requirement

R14. Each Generator Operator with a Blackstart Resource shall perform Blackstart Resource tests, and maintain records of such testing, in accordance with the testing requirements set by the Transmission Operator to verify that the Blackstart Resource can perform as specified in the restoration plan.

[Violation Risk Factor = Medium] [Time Horizon = Operations Planning]

14.1. Testing records shall include at a minimum: name of the Blackstart Resource, unit tested, date of the test, duration of the test, time required to start the unit, an indication of any testing requirements not met under Requirement R7.

14.2. Each Generator Operator shall provide the blackstart test results within 30 calendar days following a request from its Reliability Coordinator or Transmission Operator.

Corrective action plan :

14.3 Each Generator Operator shall, within 10 calendar days of an indication of any testing requirements not met under Requirement R7: [*Violation Risk Factor:*

High] [*Time Horizon: Operations Planning, Long*]‐*Term Planning*

-Develop a Corrective Action Plan (CAP) for the identified Blackstart Resource, and an evaluation of the CAP's applicability to the entity's other Blackstart Ressource including other locations; or

-Explain in a declaration why corrective actions are beyond the entity's control or

would not improve BES reliability, and that no further corrective actions will be

taken.

-Submit the conclusion(s) to the Transmission Operator

Typo from M15 to be corrected in coordination with R15.quirement :

M15 Each Generator Operator with a Blackstart Resource shall have an electronic or hard copy of the training program material provided to its operating personnel responsible for the startup and energizing a bus of its Blackstart Resource generation units and a copy of its dated training records including training dates and durations showing that it has provided training in accordance with Requirement R15.

Likes 0	
Dislikes 0	

Response

Tim Kucey - PSEG - PSEG Fossil LLC - 5

Answer	
Document Name	

Comment

adopt comments of PJM WRT EOP-005-3 R6

Likes 0	
Dislikes 0	
Response	

M Lee Thomas - Tennessee Valley Authority - 5

Answer	
Document Name	

Comment

In EOP-006-3 R1 the requirement states "The scope of the Reliability Coordinator's restoration plan starts when Blackstart Resources are utilized to re-energize a shutdown area of the Bulk Electric System (BES), or separation has occurred between neighboring Reliability Coordinators, or **an energized island has been formed on the BES within the Reliability Coordinator Area**." On the other hand the restoration plan ends, "…when all of its Transmission Operators are interconnected and its Reliability Coordinator Area is connected to all of its neighboring Reliability Coordinator Areas." If an island was created internal to a TOP around a hydro plant for example, this would fall within the scope of the RC Restoration plan to start since it would be an island on the BES within the Reliability Coordinator Area. It would also meet the requirement to end the RC Restoration Plan because all TOps and RC Areas would still be interconnected. It is reasonable to assume that the drafting team does not anticipate a Reliability Coordinator implementing their RC Restoration Plan and then ending their RC Restoration plan at the same time. The drafting team should clarify when the RC Restoration Plan should be implemented such that the Requirement does not conflict with itself.

In EOP-005-3, it is very clear the TOp restoration plan begins when a Blackstart Resource is required to restore the a shut down area to service. This is different than when the RC Restoration Plan begins in EOP-006-3. There could be instances where the RC implements their restoration plan but no TOp within that RC implements their restoration plan. It is recommended that the standard drafting team also update EOP-006-3 R1 to better coordinate with the start and end of the TOp Restoration plans .

The RC restoration plan is developed for the RC but it contains criteria that the TOp will need to follow during system restoration. For example, EOP-006 R1.2 sets criteria and conditions for re-establishing interconnections for neighboring TOps. R1.6 sets criteria for transferring operations and authority back to the Balancing Authority. It could be more clear in EOP-005 that the TOps restoration plan should be developed in coordination with its Reliability Coordinator restoration plan. For example, the criteria and conditions for re-establishing interconnections with other Transmission Operators defined in the RC restoration plan according to EOP-006 R1.2 should inform the TOp restoration plan when the TOp is developing language to meet EOP-005 R1.3 procedures for restoring interconnections with other Transmission Operators. We recommend changing the subrequirement R1.1 in EOP-005 to state the TOp restoration plan shall include, "Strategies for system restoration that ***meet the criteria defined in the Reliability Coordinator's restoration plan and*** are coordinated with the Reliability Coordinator's high level strategy for restoring the interconnection."

We recommend that where requirements are removed from the standard, that the number for the deleted requirement remain and be notated as "Retired," "Removed," or "Intentionally left blank," so that utilities do not have to perform unnecessary updates of compliance documentation simply for the sake of renumbering requirement references.

Likes 0	
Dislikes 0	
Response	

Mike Smith - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	
We do not understand the justifications for the change made to R1 (“to a state whereby the choice of the next Load to be restored…”). We’d like to request for the Standard Drafting Team to provide Rationale on the purpose of the change and example of where the choice of next Load to be restored “would be” driven by the need to control the frequency or voltage. Alternatively, the SDT may modify the wording to clarify.	
Likes 0	
Dislikes 0	
Response	