Comment Report

Project Name:	2021-04 Modifications to PRC-002 | Draft 1
Comment Period Start Date:	6/9/2022
Comment Period End Date:	7/25/2022
Associated Ballots:	2021-04 Modifications to PRC-002 | Draft 1 Implementation Plan IN 1 OT 2021-04 Modifications to PRC-002 | Draft 1 PRC-002-4 | Non-binding Poll IN 1 NB 2021-04 Modifications to PRC-002 | Draft 1 PRC-002-4 IN 1 ST

There were 67 sets of responses, including comments from approximately 152 different people from approximately 98 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the revisions to Requirement 1?

2. Do you agree with including the implementation plan information in proposed Requirement R13?

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	SPP RE	SRC 2022	Charles Yeung	SPP	2	MRO
					Ali Miremadi	CAISO	1	WECC
					Helen Lainis	IESO	1	NPCC
					Matt Goldberg	ISONE	1	NPCC
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Greg Campoli	NYISO	1	NPCC
					Elizabeth Davis	PJM	2	RF
James Mearns	James Mearns			NCPA HQ	Jeremy Lawson	Northern California Power Agency	5	WECC
					Marty Hostler	Northern California Power Agency	4	WECC
					Dennis Sismaet	Northern California Power Agency	6	WECC
					Michael Whitney	Northern California Power Agency	3	WECC
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					Marc Donaldson	Tacoma Public Utilities (Tacoma, WA)	3	WECC

					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
DTE Energy - Detroit Edison Company	Karie Barczak	3		DTE Energy - DTE Electric	Adrian Raducea	DTE Energy - Detroit Edison Company	5	RF
					Patricia Ireland	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
MRO	Kendra Buesgens	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Jamie Monette	Allete - Minnesota Power, Inc.	1	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc.	2	MRO
					LaTroy Brumfield	American Transmission Company, LLC	1	MRO
					Bryan Sherrow	Kansas City Board Of Public Utilities	1	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO

					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					David Heins	Omaha Public Power District	1,3,5,6	MRO
					George Brown	Acciona Energy North America	5	MRO
					Jaimin Patel	Saskatchewan Power Corporation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC,Texas RE	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
LaKenya VanNorman	LaKenya VanNorman		SERC	Florida Municipal Power Agency (FMPA) and Members	Chris Gowder	Florida Municipal Power Agency	5	SERC
					Dan O'Hagan	Florida Municipal Power Agency	4	SERC
					Carl Turner	Florida Municipal Power Agency	3	SERC
					Jade Bulitta	Florida Municipal Power Agency	6	SERC
					Don Cuevas	Beaches Energy Services	1	SERC
					Carolyn Woodard	Beaches Energy Services	3	SERC
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF

					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Tricia Bynum	FirstEnergy - FirstEnergy Corporation	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF
Michael Johnson	Michael Johnson		WECC	PG&E All Segments	Marco Rios	Pacific Gas and Electric Company	1	WECC
					Sandra Ellis	Pacific Gas and Electric Company	3	WECC
					James Mearns	Pacific Gas and Electric Company	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Harish Vijay Kumar	IESO	2	NPCC
					David Kiguel	Independent	7	NPCC
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC

Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Shivaz Chopra	New York Power Authority	5	NPCC
Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC
Nurul Abser	NB Power Corporation	1	NPCC
Randy MacDonald	NB Power Corporation	2	NPCC
Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
Vijay Puran	NYSPS	6	NPCC
ALAN ADAMSON	New York State Reliability Council	10	NPCC
Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
Brian Robinson	Utility Services	5	NPCC
Quintin Lee	Eversource Energy	1	NPCC
John Pearson	ISONE	2	NPCC

					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro-Quebec	2	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC

1. Do you agree with the revisions to Requirement 1?

Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
1) Manitoba Hydro is unclear on the intent of the changes made to R1, which requires SER and FR data for the remote end? 2) For clarity, Manitoba Hydro recommends that the sentance: "Notify other owners of BES Elements, for which the Transmission Owner does not record SER or FR data, connected directly to those BES buses that they are responsible for recording the SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1. If the owner of a BES Element is no longer required to have SER or FR data, notify the owner within 90 calendar days." be reworded to read "Notify other owners of BES Elements directly connected to those BES buses, for which the Transmission Owner does not record SER or FR data that they are responsible for recording the SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1. If the owner of a BES Element is no longer required to have SER or FR data, notify the owner within 90 calendar days.”	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
The meaning and importance of the SDT’s intentional addition of the word “directly” to R3 is unclear. Please consider providing a robust technical definition, additional clarification, and/or example(s) from a compliance perspective regarding the importance of adding the word “directly” as stated in R3.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	

BC Hydro thanks the drafting team for their efforts and offers the following comments and suggestions.

The revised wording of Requirement R1 Part 1.2 references responsibilities for recording the SER or FR data while the revised Requirement R1 Part 1.3 mandates that the Transmission Owner (TO) notify other owners of their responsibilities. These revisions could be interpreted as an obligation of the TO to educate other utilities regarding their responsibilities. BC Hydro's understanding, in line with the verbal drafting team's clarifications during the July 6, 2022 industry webinar, is that to meet the intent of Requirement R1 (including Part 1.3) the TO is only required to provide notification to other owners of BES Elements subject to PRC-002 once this identification was made in accordance with Part 1.1. Also, the notification required in Part 1.3 is necessary only for newly identified BES Elements, or BES Elements that no longer require to have SER of FR data recorded. Please confirm whether this understanding is accurate.

BC Hydro recommends that the Requirement R1 Part 1.3 be revised to remove the "of their responsibilities" wording. Below is suggested wording for Requirement R1 Part 1.3.

"**1.3** Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and, if necessary, notify other owners in accordance with Part 1.2."

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

AEP would like to express its overall support of the first phase of Project 2021-04. Our negative votes in this ballot period are in response *only* to our objections stated below that the illustrative examples are provided outside of the standard within in the Technical Rationale document, rather than embedded within the standard itself.

Technical Rationale documents are to assist in the technical understanding of a requirement and/or Reliability Standard, and are not to include compliance examples or compliance language. That being said, the examples provided in the proposed Technical Rationale document on pages 4 through 9 appear to go beyond mere "technical understanding" of the obligations and could possibly be referred to in determination of compliance of those obligations. As such, we believe it would be more appropriate for this content to be embedded within the standard itself, perhaps as an "Attachment 3."

Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	

Comment	

Instead of making the Transmission Owner state in their notification that another owner is responsible for SER and/or FR data, PRC-002 should clearly state compliance responsibilities for all entities. BPA suggests R1 be restructured to clearly state what information the notifications shall contain. R1 should also state owner responsibilities in the event that a notification is received from another owner that SER and/or FR data is not being recorded by the Transmission Owner who identified the BES bus. This allows for compliance responsibility to be stated in the standard rather than have Transmission Owners mandate compliance responsibilities to other BES element owners. If the Transmission Owner does not have any BES Elements that do not have SER and/or FR data per PRC-002-4, BPA feels the notifications to other owners is still valuable to ensure PRC-002 compliance has been communicated to all other owners. BPA realizes this suggested change also impacts the changes to PRC-002-4 Technical Rationale. However, if notifications are needed regardless of whether or not another owner requires SER and/or FR data, the provided examples in the PRC-002-4 Technical Rationale for R1 may not be needed.

Suggested R1 changes are as follows:

R1. Each Transmission Owner shall: *[Violation Risk Factor: Lower] [Time Horizon: Long-term Planning]*

1.1. Identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required by using the methodology in PRC-002-4, Attachment 1.

1.2. Notify other owners of their BES Elements connected directly to those BES buses *identified in Part 1.1. This notification shall:*

1.2.1 *Be sent within 90 calendar days of completion of Part 1.1.*

1.2.2 *Include identified BES Elements where the Transmission Owner has SER and/or FR data that meet the requirements of PRC-002-4.*

1.2.3 *Include identified BES Elements where the Transmission Owner does not have SER and/or FR data and will require SER and/or FR data monitoring from the connected owner to meet the requirements of PRC-002-4.*

1.2.4 *Include identified BES Elements, if any, that were removed from the BES bus list identified in Part 1.1 and no longer require SER and/or FR data to meet the requirements of PRC-002-4.*

1.3. *Review notifications received under Part 1.2 to ensure BES Elements identified under Part 1.2.3 meet the requirements of PRC-002-4.*

1.4. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and, if necessary, notify other owners *in accordance with Part 1.2.*

Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

The MRO NSRF agrees with revising R1 to clarify the notification and responsibility for FR/SER data. These revisions will reduce the compliance evidence scope for storing notifications that do not require the recipient owner to take action.

The examples in the Technical Rationale document for Figures 1-8 are helpful. We request the team consider providing some example diagrams or clarification to further define "directly connected" for 1) how a center breaker is addressed on a breaker and a half configuration since these breakers do not appear to be "directly" connected to a bus, 2) how a line connected shunt reactor breaker is addressed that is inside the substation boundary but on the line side of two ring or breaker and a half breakers.	
Likes 2	Lincoln Electric System, 1, Johnson Josh; Corn Belt Power Cooperative, 1, brusseau larry
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	
Reclamation supports the attempt to clarify R1 but recommends additional clarity is needed regarding the scope of BES Elements in R1.2. According to Attachment 1, each TO is responsible to evaluate equipment it owns. R1.2 brings in other owners, so it seems obvious that one TO would not be responsible for recording SER or FR data on another owner's equipment, yet the TO is required to notify the other owner of this. Reclamation recommends R1.2 be reworded to clarify the notification goes to "owners of other BES Elements…". Reclamation recommends removing the proposed last sentence of R1.2 ("If the owner of a BES Element is no longer required to have SER or FR data, notify the owner within 90 calendar days.") A compliance obligation to perform this notification does not impact reliability and has no value.	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	No
Document Name	
Comment	
MidAmerican supports MRO NSRF comments: The MRO NSRF agrees with revising R1 to clarify the notification and responsibility for FR/SER data. These revisions will reduce the compliance evidence scope for storing notifications that do not require the recipient owner to take action. The examples in the Technical Rationale document for Figures 1-8 are helpful. We request the team consider providing some example diagrams or clarification to further define "directly connected" for 1) how a center breaker is addressed on a breaker and a half configuration since these breakers do not appear to be "directly" connected to a bus, 2) how a line connected shunt reactor breaker is addressed that is inside the substation boundary but on the line side of two ring or breaker and a half breakers.	
Likes 0	

Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	No
Document Name	
Comment	
The language as proposed in R1 Part 1.2 and 1.3 needs to be clarified to remove the interpretion that obligaties/mandates the TO to set responsibilities of other utilites.	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 3 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas & Electric (SIGE) appreciates the opportunity to respond and thanks the drafting team for their efforts. While the changes to R1 do not directly impact SIGE's procedures, SIGE recognizes the potential that the revisions may be burdensome on industrial customers and municipalities that may not readily have access to SER or FR data at the time of notification.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	

AZPS supports the revisions to Requirement 1 in principal but recommends that the STD incorporate the revised language, suggested in EEI's submittal of comments, to clarify the language within R1, subpart 1.3 to the following:

"Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and, **if the BES buses for which sequence of events recording (SER) and fault recording (FR) data is required has changed,** then notify other owners of their responsibilities **as it relates to the affected** BES Elements, in accordance with Part 1.2."

Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	No
Document Name	
Comment	

The language as proposed in R1 Part 1.2 and 1.3 needs to be clarified to remove the interpretation that obligates/mandates the Transmission Owner to set responsibilities of other utilities.

Please see BPA's suggested edits.

Likes 0	
Dislikes 0	
Response	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	

CenterPoint Energy Houston Electric, LLC (CEHE) recommends the following revisions to part 1.2 for clarity.

1.2 Notify other owners of BES Elements, for which the Transmission Owner does not record SER or FR data, connected directly to those BES buses that *the other owner* is responsible for recording the SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1. If the *other* owner of a BES Element is no longer required to have SER or FR data, notify the *other* owner within 90 calendar days.

CEHE recommends that Part 1.3 include a reference to the implementation language that has been moved from the implementation plan to R13.

1.3 Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and, if necessary, notify other owners of their responsibilities in accordance with Part 1.2 *and implement the re-evaluated list of BES buses as per Requirement R13 Part 13.1.*

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

MPC supports MRO NERC Standards Review Forum comments.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

Ameren agrees with the EEI comments.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 6, 5; Jennifer Flandermeyer, Evergy, 1, 3, 6, 5; Jeremy Harris, Evergy, 1, 3, 6, 5; Marcus Moor, Evergy, 1, 3, 6, 5; - Alan Kloster

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the response of the Edison Electric Institute (EEI) to questions #1.

Likes 0	
Dislikes 0	

Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
Oncor appreciates the opportunity to respond and thanks the drafting team for their efforts. Oncor supports comments provided by CenterPoint Energy Houston Electric, LLC (CEHE) as follows: 1.2. Notify other owners of BES Elements, for which the Transmission Owner does not record SER or FR data, connected directly to those BES buses that *the other owner* is responsible for recording the SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1. If the *other* owner of a BES Element is no longer required to have SER or FR data, notify the *other* owner within 90 calendar days. CEHE recommends that Part 1.3 include a reference to the implementation language that has been moved from the implementation plan to R13. 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and, if necessary, notify other owners of their responsibilities in accordance with Part 1.2 *and implement the re-evaluated list of BES buses as per Requirement R13 Part 13.1.*	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	
See Comments Submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	

Exelon concurs with the clarification suggested in the EEI comment.

On behalf of Exelon, Segments 1 & 3

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

The language within R1, subpart 1.3 should be clarified and we offer the following:

1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and, **if the BES buses for which sequence of events recording (SER) and fault recording (FR) data is required has changed,** then notify other owners of their responsibilities **as it relates to the affected** BES Elements, in accordance with Part 1.2.

Likes 0	
Dislikes 0	

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric

Answer	No
Document Name	

Comment

DTE abstains.

Likes 0	
Dislikes 0	

Response

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA) and Members

Answer	No

Document Name	

Comment

The SAR from Glencoe noticeably identifies two issues. The proposed standard revision addresses only one of those issues (and we believe, insufficiently). The original SAR (Before SDT added some items to the list) identifies the following two issues:

1) R1.2 infers all owners of BES Elements connected to the identified buses should provide SER and FR data, regardless of what type of Element they own, while R3 clearly identifies that FR data is only required for two categories of Elements – Transformers with low side operating voltage of 100kV or above and Transmission lines. This means that entities that own transformers with a low side operating voltage below 100kV are not required to provide FR data but are being sent notifications per R1.2 with the implication they must provide it. The proposed standard revisions do nothing to clear up this issue.

2) Since all owners, whether joint or sole, of every BES Element connected to the identified bus or buses, are being notified, many owners are being notified but are not in a position to capture data that is consistent with the intent of the standard. Specifically, it is quite common for ownership to change along the length of a transmission line, often many miles away from the bus that was identified in R1.1. As such, the “remote joint owner” of the BES Element has no equipment within the substation fence of the bus that was identified and is not in any position to capture any data relative to the identified bus, since it has no measurement equipment in that location. It was clearly not the original intent of the standard to require that every element connected to an identified bus have measurements at both ends (remote and local). We believe the intent of the original standard was clear that when a bus is identified, measurements obtained would be at the local bus location (whether terminal flows or bus voltages, they would be at that bus location). Modifying the language in R1.2 and R3 to include “directly connected” unfortunately does not fix the clear overreach that many auditors have inferred. If a transmission line is “jointly owned”, they consider it the responsibility of both owners to obtain the FR and SER data, even though in most cases the “joint” owner takes over ownership at the remote end of the line.

In order to fully address the original SAR (as we read it), the standard should be revised to make it clear only owners of equipment local (again, Directly Connected doesn’t help since the term BES Element has no fractional ownership in its definition) to the substation bus identified have the obligation to record data, and it should be clarified that only those entities that own BES Elements listed in R3.2 must provide FR data regardless of receipt of a notification. Ideally no notification would be required but SER data coverage must also be considered, since today both are performed with one notification.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment

Clarification is required with respect to required notifications. Suggestion is made to include in Appendix 1 the BES Elements exclusion of the Transformers that have a low-side operating voltage below 100kV. This will eliminate the unnecessary notification of BES Element Owners in accordance to R1, only to exclude it afterwards as per R3, Part 3.2, sub 3.2.1.

Likes 0	
Dislikes 0	

Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 5 - WECC	
Answer	No
Document Name	
Comment	
PacifiCorp agrees with revising R1 to clarify the notification and responsibility for FR/SER data. These revisions will reduce the compliance evidence scope for storing notifications that do not require the recipient owner to take action. The examples in the Technical Rationale document for Figures 1-8 are helpful. We request the team consider providing some example diagrams or clarification to further define "directly connected" for 1) how a center breaker is addressed on a breaker and a half configuration since these breakers do not appear to be "directly" connected to a bus, 2) how a line connected shunt reactor breaker is addressed that is inside the substation boundary but on the line side of two ring or breaker and a half breakers.	
Likes 0	
Dislikes 0	
Response	
Glenn Pressler - CPS Energy - 1,3,5	
Answer	No
Document Name	
Comment	
CPS Energy feels that 1.2 still needs work to make clear who is responsible for providing SER or FR data in stations where multi-owners are involved. When used in conjunction with the technical reference document (Technical Rationale), it is mostly fine, however, without the technical reference, the standard is not entirely clear who is responsible for busses with multi-owners. In the first sentence of 1.2, the sentence "for which the Transmission Owner does not record SER or FR data" really needs to be reworded to include "and is not responsible for recording SER or FR data" to notify the other owner(s) of the responsibility for recording the SER or FR data. However, need to remove a new requirement obligation of the studying entity, in R1 Part 1.2 and 1.3, to be required to assign requirement obligations to another entity; this needs to be fixed to remove the interpretation that obligates the Transmission Owner to set responsibilities of other entities. Examples in standard would be preferred; the best solution is to provide complete clarity and add the technical reference with diagrams and explanations to the end of the standard, as is done in PRC-025-2, for example.	
Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
WECC agrees with the idea and intent but believes the wording in 1.2 could be improved. 1) it states "Notify other owners of BES elements, for which the Transmission Owner does not record SER of FR data..." This could be confusing since the other "owner" could also be a Transmission Owner. 2) while recording of SER and FR data is one way of providing the data. Calculation of required data is also possible. So use of "recording" may be implying the need for equipment that is not explicitly specified by the standard. WECC recommends that the Drafting Team consider the following change in wording: "Notify other owners of BES elements, for which the Transmission Owner performing the assessment per Attachment 1 does not obtain SER or FR data, that the BES Element owners are responsible for providing the SER or FR data...."	
Likes 0	
Dislikes 0	
Response	
Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no proposed comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	

Constellation has no proposed comments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

ITC agrees with these revisions. The R1 changes provide clarity that should reduce the number of unnecessary notifications made and received by each entity.

Likes 0	
Dislikes 0	

Response

Patricia Lynch - NRG - NRG Energy, Inc. - 5

Answer	Yes
Document Name	

Comment	
NRG generally agrees with the revisions. The additions make the requirements clear regarding who has the obligations for installing SER or FR recorders. We are hesitant that the Transmission Owner is the party making the decision regarding whether it will be them or the Generator Owner to install the recorder. We would favor a third party, like an RC, to make the determination or to encourage discussions between the affected owners. NRG has had good experiences working with TOs to install recorders in the past and encourage discussions between the TO and GO regarding who should perform the installation.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FE suggest clarifying R1.3 to state “notify other owners of changes in their responsibilities”. 1.3. Re-evaluate all BES buses at least once every five calendar years in accordance with Part 1.1 and **if necessary, notify** other owners **of changes in their responsibilities**, if any, in accordance with Part 1.2, and implement the re-evaluated list of BES buses as per the Implementation Plan. The reason for this modification is that the “other owners” have been previously notified in Part 1.2 of their responsibility; so, the “other owners” should only be notified of changes to their responsibilities.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	
Comment	
PG&E supports the revisions to Requirement R1, but has the following input the SDT should consider for R1.2:	

R1.2 indicates for the Transmission Owner - "… If the owner of a BES Element is no longer required to have SER or FR data, notify the owner within 90 calendar days."

PG&E concern is the language does not address what happens if there are changes between the 5-year evaluation periods resulting in changes to the SER and FR data collection capabilities. There does not appear to be any requirement to communicate those changes so the owner either stops the work that is no longer required or starts work that would be required to maintain the reliability of the Bulk Electric System (BES).

PG&E recommends the SDT consider the above and determine how to address this condition to avoid work that is no longer required or could lead to reliability issues for work that should be done

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 5

Answer	Yes
Document Name	

Comment

Black Hills Corpoariton agrees with EEI's comments.

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	Yes
Document Name	

Comment

Black Hills Corporation agrees with EEI comments.

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Tri-State agrees with the revisions to Requirement 1 however, proposes the following language for clarity: "Notify other owners of BES Elements directly connected to those BES buses, for which the Transmission Owner does not record SER or FR data that they are responsible for recording the SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1. If the owner of a BES Element is no longer required to have SER or FR data, notify the owner within 90 calendar days."	
Likes 0	
Dislikes 0	
Response	

James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ	
Answer	Yes
Document Name	
Comment	
The suggested revisions to Requirement 1 are consistent with the principle that the TO/TP remain responsible for identification of locations requiring FR/SER/DDR capability.	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wendy DeVries - CMS Energy - Consumers Energy Company - 1,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brendan Baszkiewicz - Eversource Energy - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Zack Heim, Salt River Project, 5, 3, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ayslynn McAvoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
David Reinecke - Seminole Electric Cooperative, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Marc Sedor - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; John Merrell, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; Marc Donaldson, Tacoma Public Utilities (Tacoma, WA), 3, 1, 4, 5, 6; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE noticed the term “owners” throughout the requirements. Texas RE recommends clarifying that “owners” refers to NERC-registered Transmission Owners or Generation Owners to eliminate the possibility that a non-NERC registered entity may be designated within a Facility that requires FR/SER data per a registered entity’s determination to ensure effective review of materials after an event.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF has no comments.	
Likes 0	
Dislikes 0	
Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
No response.	
Likes 0	
Dislikes 0	
Response	

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC 2022

Answer	
Document Name	

Comment

SRC submits no response to this question.

Likes 0	
Dislikes 0	

Response

2. Do you agree with including the implementation plan information in proposed Requirement R13?

Glenn Pressler - CPS Energy - 1,3,5	
Answer	No
Document Name	
Comment	
Not necessarily against the 3-year term; would prefer calendar years or calendar months (e.g. 36 calendar months). Also, make clear that both Transmission Owner and other owners of BES elements notified per R1/R5 need to have the equipment installed in 3 years; same concern, 3-years from what; fix by specifying three calendar-years from date notified. Noted the Technical Rationale references "Three (3) calendar years.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	
R13 could result in a variable number of notifications per year resulting in undue burden on the utility to implement.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 5 - WECC	
Answer	No
Document Name	
Comment	
PacifiCorp agrees with the need for including the re-evaluation and implementation plan as R13. It aligns with the prior implementation plan and will clearly carry forward newly applicable BES elements within the standard.	

We would like to request clarification for the meaning of the word "notification" in 13.1. For example, a TO performs the 5-year re-evaluation and they do not need to notify others and are not notified by others. In this case when would the 3-year timeline start?

The NSRF recommends the following revised language: "Within three (3) calendar years of notification under Requirement R1, Part 1.2, or completion of Requirement R1, Part 1.3, as applicable, have SER or FR data …"

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment

Due to current Supply Chain challenges and based of Planned Outages Schedule interval of 3 years for nuclear generating units a suggestion is made that where the determination has been made that the DMEs are required to be installed, the implementation of the SER, FR, and DDR shall be the result of commonly agreed scheduled, negotiated between the TO and GO.

Likes 0	
Dislikes 0	

Response

James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ

Answer	No
Document Name	

Comment

This approach seems inconsistent with the "effective date" approach identified in other NERC requirements with staged implementation dates and appears to dilute the effectiveness of the Implementation Plan concept.

Likes 0	
Dislikes 0	

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
DTE is concerned with the prescriptive nature of a three (3) year notification clock. Perhaps a reasonable Corrective Action Plan could be developed?	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
We agree with including the implementation plan information within proposed Requirement R13 but also suggest Part 13.1 and Part 13.2 be revised to state, "Within three (3) calendar-years…", instead of "Within three (3) years. Three calendar-years would be helpful for the installation of new equipment, since a calendar-year ends on December 31st vs. stating within (3) years which could be interpreted as three years from the notification date. The Technical Rationale references, "Three (3) calendar years…"	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon concurs with the clarification suggested in the EEI comment. On behalf of Exelon, Segments 1 & 3	
Likes 0	
Dislikes 0	
Response	

Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	
See Comments Submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Eric Shaw - Eric Shaw On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Eric Shaw	
Answer	No
Document Name	
Comment	
In consideration of recent material shortages and supply chain disruptions, Oncor recommends an implementation period of 5 calendar years for Requirement 13 Part 13.1 and Part 13.2.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 6, 5; Jennifer Flandermeyer, Evergy, 1, 3, 6, 5; Jeremy Harris, Evergy, 1, 3, 6, 5; Marcus Moor, Evergy, 1, 3, 6, 5; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the response of the Edison Electric Institute (EEI) to questions #2.	
Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	No
Document Name	
Comment	
Northern Indiana Public Service Company supports the addition of Requirement R13, but recommends changing the period of time from "three year" to "three calendar year" to be consistant with other parts of the standard.	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with the EEI comments.	
Likes 0	
Dislikes 0	
Response	

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	No
Document Name	
Comment	
I'm concerned that 3 years may be insufficient to plan/design new SER/FR installations, procure equipment, and install the equipment, particularly for power plants (GO) where such installation should be coordinated with plant outage schedules in order to not adversely affect plant availability. The 3 year implementation time frame might be to constrictive especially in light of recent material shortages. Suggest a 7 year time frame would allow BES element owners time to work the project into their schedule and procure equipment and resources.	
Likes 0	
Dislikes 0	

Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
MPC supports MRO NERC Standards Review Forum comments.	
Likes 0	
Dislikes 0	
Response	
Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC recommends an implementation period of 5 calendar years for Requirement 13 Part 13.1 and Part 13.2.	
Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	No
Document Name	
Comment	
We are concerned that 3 years may be insufficient to plan/design new SER/FR installations, procure equipment, and install the equipment, particularly for power plants (GO) where such installation should be coordinated with plant outage schedules in order to not adversely affect plant availability.	
Likes 0	
Dislikes 0	
Response	

Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	No
Document Name	
Comment	
Recommend a similar path that PRC-026 R3 and R4 takes: upon notification of the need to install a DDR (from R5) create a corrective action plan and implement it.	
Likes 0	
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
AZPS supports the inclusion of the implementation plan in proposed Requirement R13 but recommends that the STD incorporate the revised language, suggested in EEI's submittal of comments, to clarify the language within R12, subparts 13.1 and 13.2 to the following: "Within three (3) calendar-years…", instead of "Within three (3) years. Three calendar-years would be helpful for the installation of new equipment, since a calendar-year ends on December 31st vs. stating within (3) years which could be interpreted as three years from the notification date. The Technical Rationale references, "Three (3) calendar years…"	
Likes 0	
Dislikes 0	
Response	

Leslie Hamby - Southern Indiana Gas and Electric Co. - 3 - RF	
Answer	No
Document Name	
Comment	
SIGE recommends the implementation period be amended from "three (3) years" to "five (5) calendar years". The addition of "calendar" is to mirror the language in R1. SIGE believes the three-year implementation period may be too restrictive given set project cycles and several challenges faced by the industry including outage constraints due to capacity shortfalls and long lead-times due to supply chain issues.	

Likes 0	
Dislikes 0	

Response

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3

Answer	No
Document Name	

Comment

MidAmerican supports MRO NSRF comments:

The MRO NSRF agrees with the need for including the re-evaluation and implementation plan as R13. It aligns with the prior implementation plan and will clearly carry forward newly applicable BES elements within the standard.

We would like to request clarification for the meaning of the word “notification” in 13.1. For example, a TO performs the 5-year re-evaluation and they do not need to notify others and are not notified by others. In this case when would the 3-year timeline start?

The NSRF recommends the following revised language: “Within three (3) calendar years of notification under Requirement R1, Part 1.2, or completion of Requirement R1, Part 1.3, as applicable, have SER or FR data …”

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	No
Document Name	

Comment

The “General Considerations” bullet in the implementation plan pertaining to Requirement R13 is unclear. Reclamation recommends aligning R13 with the five-year requirement to avoid the potential for entities to be placed in a constant state of review.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No

Document Name	
Comment	
The MRO NSRF agrees with the need for including the re-evaluation and implementation plan as R13. It aligns with the prior implementation plan and will clearly carry forward newly applicable BES elements within the standard. We would like to request clarification for the meaning of the word “notification” in 13.1. For example, a TO performs the 5-year re-evaluation and they do not need to notify others and are not notified by others. In this case when would the 3-year timeline start? The NSRF recommends the following revised language: “Within three (3) calendar years of notification under Requirement R1, Part 1.2, or completion of Requirement R1, Part 1.3, as applicable, have SER or FR data …”	
Likes 2	Lincoln Electric System, 1, Johnson Josh; Corn Belt Power Cooperative, 1, brusseau larry
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
While AEP acknowledges that the existing Implementation Plan for the standard under enforcement has a “three year” period of time to have data in response to notification(s) under R1, we recommend changing this to “three calendar years” under the proposed R13.	
Likes 0	
Dislikes 0	
Response	
Scott Kinney - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
R13 could result in a variable number of notifications per year resulting in undue burden on the utility to implement.	
Likes 0	
Dislikes 0	
Response	

Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
R13 could result in a variable number of notifications per year resulting in undue burden on the utility to implement.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Suggest implementation period be amended from 3-years to 4-years. The requirement for a 3-yr compliance period will conflict with previously scheduled and planned outage/maintenance/fueling cycles since: (a) the ability to install equipment is significantly affected by outage constraints, equipment lead-times and availability and, (b) the Covid pandemic has significantly impacted supply chain and availability of work resources. Overall, the 3-year window creates a condition whereby an entity must fast-track the installation of monitoring equipment over other work which better supports grid stability. Additionally, the 3-year implementation period is especially disadvantageous to nuclear sites with 2-year refueling cycles/outages.	
Likes 0	
Dislikes 0	
Response	
Wendy DeVries - CMS Energy - Consumers Energy Company - 1,5 - RF	
Answer	No
Document Name	
Comment	
The 3 year implementation time frame might be to constrictive especially in light of recent material shortages. Suggest a 7 year time frame would allow BES element owners time to work the project into their schedule and procure equipment and resources.	
Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Tri-State agrees with moving the three year notification requirement from the implementation plan directly to the standard to provide more clarity.	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF has no comments.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	

Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	Yes
Document Name	
Comment	
Black Hills Corpoariton agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments	
Answer	Yes
Document Name	

Comment	
PG&E supports the proposed Requirement R13, but has the following question and recommendation: Does the three-year implementation trigger start on the day that the affected BES Element owner is informed of their new SER, FR, and/or DDR data obligation(s). The current Requirement language is not clear on the trigger start. PG&E recommends this be clearly indicated to avoid interpretation differences between the Registered Entity and Regional Entity	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	Yes
Document Name	
Comment	
Yes, but consider stating three calendar years as noted by APS.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC agrees with including the implementation plan information in the proposed Requirement R13, however believes additional clarity should be provided. Proposed language indicates a 3-year implementation plan upon receipt of notification in R1.3, however a 3-year implementation should also be included for the entity performing the reevaluation and identifies their own buses in R1.1. This seems implied but should be explicit.	
Likes 0	
Dislikes 0	
Response	

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

Deanna Carlson - Cowlitz County PUD - 5	
Answer	Yes
Document Name	
Comment	
No comment at this time.	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Constellation agrees with the proposed Requirement R13, however, recommends the replacement of "within three (3) years of notification" to three (3) calendar years of notification. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Alison Mackellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation agrees with the proposed Requirement R13, however, recommends the replacement of "within three (3) years of notification" to three (3) calendar years of notification. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	Yes
Document Name	
Comment	
Since the term Calendar Year is used in Parts 1.3 and 5.4, WECC recommends that the Drafting Team consider replacing the words "Three (3) years" with the words "36 months." This would provide more clarity than using two different meanings of the term "year" within the same standard and would be consistent with other terminology in the standard.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Manitoba Hydro proposes that language in sections 13.1. and 13.2. be revised to read:	

13.1. Within three (3) years of **receiving** notification under Requirement R1, Part**s 1.2 and** 1.3, have SER or FR data as applicable for BES Elements directly connected to BES buses identified during the re-evaluation.

13.2. Within three (3) years of **receiving** notification under Requirement R5, Part**s 5.3 and** 5.4, have DDR data for BES Elements identified during the re-evaluation.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA) and Members

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Marc Sedor - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kristine Ward - Seminole Electric Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Reinecke - Seminole Electric Cooperative, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ayslynn McAvoy - Arkansas Electric Cooperative Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Zack Heim, Salt River Project, 5, 3, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brendan Baszkiewicz - Eversource Energy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC 2022	
Answer	
Document Name	
Comment	
SRC submits no response to this question.	

Likes 0	
Dislikes 0	

Response

Dana Showalter - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

ERCOT noticed that the Implementation Plan for PRC-002-4 states, “The elements of the Implementation Plan for PRC-002-3 are incorporated herein by reference and shall remain applicable to PRC-002-4.” And the Implementation Plan for PRC-002-3 contains the following language:

Entities shall be 100 percent compliant with a re-evaluated list from Requirement R1 or R5 within three (3) years following the notification by the TO or the Responsible Entity that re-evaluated the list.

Thus, the three-year compliance window for BES Elements added pursuant to a re-evaluation in R1 or R5 exists pursuant to the Implementation Plan, although the SAR expressed desire to remove this compliance window from the Implementation Plan. In this case, R13 should be removed.

If the compliance window is removed from the Implementation Plan, ERCOT notes that the proposed R13 language does not fully address the compliance-window issue. R13 provides a compliance window, but does not tie the window specifically to the applicable data requirements, such as R2. Each data requirement may need to reference R13 or the SDT may want to consider putting the three-year compliance window language within each requirement rather than as a stand-alone requirement.

Regardless of where the implementation window lies, the language should be clear that the three-year compliance window only applies to *new BES Elements*, not all BES Elements, identified pursuant to the R1 and R5 review cycle.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE appreciates the SDT addressing Texas RE’s concern and moving the periodic requirements associated with R1 and R5 away from the Implementation Plan and into Requirement R13.

Texas RE recommends stating specifically which elements from the PRC-002-3 Implementation Plan are incorporated into the PRC-002-4 Implementation Plan. The PRC-002-4 Implementation Plan contains the phrase: “the elements of the Implementation Plan for PRC-002-3 are incorporated herein by reference and shall remain applicable to PRC-002-4”. It is not clear which elements are incorporated by reference. The PRC-

002-3 Implementation Plan, it states, “unless otherwise specified herein, the elements of the Implementation Plans for FAC-003-4, PRC002-2, PRC-023-4, and PRC-026-1 are incorporated herein by reference and shall remain applicable to FAC-003-5, PRC-002-3, PRC-023-5, and PRC-026-2.” It is unclear which is carried through to the proposed PRC-002-4 Implementation Plan as there is no section in either Implementation Plan labeled as “elements”.	
Likes 0	
Dislikes 0	
Response	

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

Wendy DeVries - CMS Energy - Consumers Energy Company - 1,5 - RF	
Answer	
Document Name	
Comment	
The implementation time frame of 3 years isn't long enough for a BES element owner to gather bids, procure materials, and schedule the work, and then install the equipment. Time frame should be extended to 7 years if not that at least, 5 years.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	
Manitoba Hydro proposes that language for requirement R3 be updated to read “Each Transmission Owner and Generator Owner shall have FR data to determine the following electrical quantities for each triggered FR for the BES Elements it owns **that are directly** connected to the BES buses identified in Requirement R1".	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
While R13 will have specified implementation times, the Violation Severity Levels for R13 do not address any severity with respect to the time specified for implementation in R13 as they do for R1 and R5. Is this intentional?	
Likes 0	
Dislikes 0	
Response	

Scott Kinney - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	
AEP thanks the Standards Drafting Team for their efforts, and for pursuing AEP's previous recommendation for the two proposed SARs to each be dealt with in separate project phases.	
Likes 0	
Dislikes 0	
Response	

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	

R13 should apply to all of R1 and R5 and not just R1.3 or R5.4. SER and/or FR data should be required within 3 years whether an applicable BES Element is identified during the Transmission/Generator Owner's re-evaluation or if a BES Element is identified per receipt of a notification from another owner per R1.2 (specifically R1.2.3 if BPA's suggested changes to R1 are accepted).

The 15% margin proposed in Attachment 1, Step 7 seems very arbitrary and doesn't seem to provide any added reliability value other than making the logistics of having to add SER or FR equipment less burdensome. Unless there is proof that a 15% margin does not adversely impact reliability of the grid, the margin should not be added.

Overall:

- The Standard should not rely on other TO/GO's to mandate requirements on other TO/GO's.
- The Standard should define what information is required in the notifications.
- All Requirements within the Standard should have a foundation in improving or maintaining reliability of the transmission system.

Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	

No additional comments.

Likes 2	Lincoln Electric System, 1, Johnson Josh; Corn Belt Power Cooperative, 1, brusseau larry
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	
Document Name	
Comment	

The proposed change to Attachment 1 Step 7 allows the possibility of significant change over time without a required change in data recording location. Reclamation recommends each re-evaluated three phase short circuit MVA be compared to the originally evaluated three phase short circuit MVA and no change is required only if the re-evaluated measurement is within 15% of the original measurement. Comparing each re-evaluated measurement to its previous measurement would allow no change in location in perpetuity so long as the difference changed by no more than 15% each re-evaluation, even if the net change over time was ultimately more than 15%.

In the Western Interconnection, entities also receive notifications from the Planning Coordinator. Therefore, Section 4.1 and Requirements R1 and R5 should be revised to include Planning Coordinators.

Reclamation recommends removing the proposed last sentence of R5.3 ("If the owner of a BES Element is no longer required to have DDR data, notify the owner within 90 calendar days.") A compliance obligation to perform this notification does not impact reliability and has no value.

To clarify that in the case of multiple RCs, each RC is responsible for its own RC Area (reference NERC Glossary of Terms "Reliability Coordinator Area"), Reclamation recommends changing the language in R5.4 as follows:

From:

Re-evaluate all BES Elements under its purview at least once every five calendar years…

To:

Re-evaluate all BES Elements in its Reliability Coordinator Area at least once every five calendar years…

Likes 0	
Dislikes 0	

Response

Alison Mackellar - Constellation - 5

Answer	
Document Name	

Comment

Constellation has no additional comments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	

Document Name	
Comment	

Constellation has no additional comments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 3	
Answer	
Document Name	
Comment	

No additional comments.

Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 5	
Answer	
Document Name	
Comment	

No comment at this time

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

Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
none	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Russell Noble - Cowlitz County PUD - 3	
Answer	
Document Name	
Comment	

Agree with BPA comments.

Likes 0	
Dislikes 0	

Response

Kenisha Webber - Entergy - NA - Not Applicable - SERC

Answer	
Document Name	

Comment

Consider the current uncertainty of supply chain issues and availability of parts.

Likes 0	
Dislikes 0	

Response

Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF

Answer	
Document Name	

Comment

The implementation time frame of 3 years isn't long enough for a BES element owner to gather bids, procure materials, and schedule the work, and then install the equipment. Time frame should be extended to 7 years if not that, at least 5 years.

Likes 0	
Dislikes 0	

Response

Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	

Comment

No additional comments.

Likes 0	
Dislikes 0	

Response

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3

Answer	
Document Name	

Comment

The implementation time frame of 3 years isn't long enough for a BES element owner to gather bids, procure materials, and schedule the work, and then install the equipment. Time frame should be extended to 7 years if not that, at least 5 years.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

For R1.3, if the other owner is recording as notified per R1.2 and the 5-year re-evaluation per R1 indicates they are to continue to record, is a re-notification needed? Would this change the evidence retention for R1?

If FE's propose change in question 1 is accepted, should the Evidence Retention be revised in section B. Compliance, Part 1.2 to extend past 5 years if necessary to capture the last notification? Revision we suggest:

From:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years.

To:

The Transmission Owner shall retain evidence of Requirement R1, Measure M1 for five calendar years or since the last notification in Part 1.2 or 1.3

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	
Document Name	

Comment

Ameren agrees with the EEI comments.

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	
Document Name	

Comment

In R5, Part 5.3, a new requirement was added for the RC to notify appropriate entities if a BES Element is no longer required to provide DDR data. This goes beyond the scope of the SAR; although the RC may notify parties when certain data is not needed, there is no reliability need or benefit for making this notification a requirement. Requirements 5.1 and 5.2 provide non-exclusive criteria for determining DDR locations; an RC may identify other DDR needs. An RC must have the authority to dictate where it needs data recorders and the triggers for recording data. Since R 5.4 requires this to be evaluated every five years, there is no need to further obligate the RC to notify when DDR data is not needed. Therefore, the language, “If the owner of a BES Element is no longer required to have DDR data, notify the owner within 90 calendar days” should be stricken.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Michael Johnson On Behalf of: Frank Lee, Pacific Gas and Electric Company, 3, 1, 5; Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; - Michael Johnson, Group Name PG&E All Segments

Answer	
Document Name	

Comment

PG&E has input on R5.3 which is the same as our comment and recommendation in Question 1 regarding R1.2. Please see our input for Question 1; the only difference is that R5.3 is related to the Reliability Coordinator.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	
Document Name	
Comment	

Delete the word "for" from the title of the IEEE C37.111 standard title. The correct name is (IEEE Standard Common Format for Transient Data Exchange (COMTRADE).

VSL Table R11, change 11.1 to 11.2 in the sentence "The TO or GO as directed by R11, Part 11.1 provided the requested data more than x days" for all severity levels, as the Requirement for the requested data is R11.2 and not R11.1.

Technical Rationale: The standard addresses SER, FR, and DDR data, therefore, consider removing the last sentence of the Technical Rationale, Page 4, the first paragraph after the bullets, that reads "As a result, this standard only requires DDR data". Or clarifying the sentence for the requirements that require DDR data only.

Technical Rationale: Page 11, Rationale R4, 3rd paragraph: should "protection System" be "Protection System"?

Technical Rationale: Page 18, Rationale for R11, 2nd paragraph should read "Providing the data within 30 calendar days (or the granted extension time), subject to Part 11.1, allows for a reasonable time to collect the data and perform any necessary computations or formatting" should read "…subject to Part 11.2", as the Requirement for the requested data is R11.2 and not R11.1.

Technical Rationale: Page 19, 3rd paragraph "Requirement R11, Part 11.1 specifies the maximum time frame of 30 calendar days to provide the data." Should read "Requirement R11, Part 11.2 specifies …"

Technical Rationale: Page 19, 4th paragraph "Requirement R11, Part 11.2 specifies that the minimum time period of 10 calendar days inclusive of the day the data was recorded for which the data will be retrievable" should read "Requirement R11, Part 1.1 …."

For added clarity: suggest adding straight and ring bus examples in the technical rationale (similar to examples in figures 3 and 4 on pg. 6) where CB 3 is owned by TO B while TO A as a BES bus owner records SER and FR data for CB 3. And explain whether notification is required or not.

Likes 0	
Dislikes 0	
Response	

Steven Taddeucci - NiSource - Northern Indiana Public Service Co. - 3	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	
Document Name	
Comment	
In regards to R1.3 if a entity identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required through the assessment required in R1.1 what is the time-frame to get evidence and possibly install equipment?	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Allen Klassen, Evergy, 1, 3, 6, 5; Jennifer Flandermeyer, Evergy, 1, 3, 6, 5; Jeremy Harris, Evergy, 1, 3, 6, 5; Marcus Moor, Evergy, 1, 3, 6, 5; - Alan Kloster	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference the response of the Edison Electric Institute (EEI) to questions #3.	
Likes 0	
Dislikes 0	
Response	
David Reinecke - Seminole Electric Cooperative, Inc. - 6	

Answer	
Document Name	
Comment	
In regards to R1.3 if an entity identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required through the assessment required in R1.1 what is the time-frame to get evidence and possibly install equipment?	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
n/a	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	
Document Name	

Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Kenya Streeter - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	
Document Name	
Comment	
See Comments Submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Marc Sedor - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	
Document Name	
Comment	
In regards to R1.3 if an entity identify BES buses for which sequence of events recording (SER) and fault recording (FR) data is required through the assessment required in R1.1 what is the time-frame to get evidence and possibly install equipment?	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE is concerned that the Technical Rationale for Requirement R1 references BES short circuit data from 2013. The grid has had a significant change in the resource mix since 2013, with the ERCOT region adding 11,650 MW of solar since 2013. Texas RE understands inverter-based resources will be addressed in the next phase of this project, with the SAR submitted by the IBRTF. Especially considering past and recent events in Odessa and California, as detailed in the Odessa Disturbance Report issued May 2021 and Multiple Solar PV Disturbances in CAISO dated April 2022, Texas RE encourages the SDT to consider a requirement for generators to have fault recording devices.

Texas RE noticed in section B. Compliance 1.3 Compliance Monitoring and Enforcement Program the term “Spot Checking” should be “Spot Check”, “Compliance Violation Investigation” should be “Compliance Investigation”, “Self Reporting” should be “Self Reports” Texas RE recommends the SDT consider adding Self-Logging.

Attachment 1 Comments

Texas RE recommends clarifying which “list” is being referenced for each step. Texas RE has the following additional comments regarding clarifying the steps in Attachment 1.

Texas RE understands the methodology as follows: A list is created in Step 1. In Step 2 the list in Step 1 is reduced to 1500 MVA or greater (with zero buses meaning the process is complete). Step 3 reduces the list in Step 2 to the 11 buses with the maximum available calculated three-phase short circuit MVA.

Texas RE noticed Step 3 does not provide guidance for more than 11 BES buses (from list in Step 2) that have ***equal*** maximum available calculated three phase short circuit MVA. The attachment is assuming non-equal buses which many larger utilities may have within their footprint.

Texas RE recommends clarifying Step 5 to state the number should be 20% of the median or 120% of the median MVA level. As the language is currently drafted, it reads if the median level were 1500 MVA Step 5 result would be 300 MVA which would mean every bus in Step 2 would require FR and SER data. If in Step 2 you reduce the list to 1500 MVA or greater then Step 6 automatically includes every bus.

Step 2 explains to reduce the list of BES buses to 1500 MVA or greater. Step 4 explains to use the 20% median level determined in Step 5. If the 20% is 300 MVA, as per Texas RE’s example above, is it the SDT’s intent to look in this range?

Step 7 (where there are 1 or more but less than or equal to 11 BES buses) appears to possibly limit FR and SER data at “the BES bus with the highest maximum available calculated three phase short circuit MVA as determined in Step 2. In other words, if all buses (1 to a maximum of 11) have the same “highest maximum available calculated three phase short circuit MVA” is the Transmission Owner only required to select one (1) BES Bus? Even if they do not have the same “highest maximum available calculated three phase short circuit MVA”, is the intent to only have FR and SER data at one (1) BES bus?

Likes 0	
Dislikes 0	

Response

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	

The NAGF provides the following comments for consideration:

1. Draft #1 PRC-002-4:

a. Recommend deleting page 2 as there are no new terms defined.

b. R13.1 and R13.2 – Replace "Within three (3) years of notification…" with "Within three (3) calendar years of notification…".

2. Attachment 1, Step 7:

a. The proposed change to Attachment 1 Step 7 allows the possibility of significant change over time without a required change in data recording location. Recommend that each re-evaluated three phase short circuit MVA be compared to the originally evaluated three phase short circuit MVA and no change is required only if the re-evaluated measurement is within 15% of the original measurement.

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

Exelon concurs with the clarification suggested in the EEI comment.

On behalf of Exelon, Segments 1 & 3

Likes 0	
Dislikes 0	
Response	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	

Comment	

ERCOT agrees with the SRC.

In R5, Part 5.3, the SDT placed a new requirement on the RC to notify owners if a BES Element is no longer required to have DDR data. This goes beyond the scope of the SAR; there is no reliability need or benefit to this notification. Requirements 5.1 and 5.2 provide non-exclusive criteria for determining DDR locations; an RC may identify other DDR needs. An RC must have the authority to dictate where it needs data recorders and the triggers for recording data. The language, “If the owner of a BES Element is no longer required to have DDR data, notify the owner within 90 calendar days” should be stricken.

Although not preferred, if the SDT retains the language regarding notification when DDR data is not required, ERCOT requests that the SDT add “of completing Part 5.1” at the end of the sentence: “If the owner of a BES Element is no longer required to have DDR data, notify the owner within ninety calendar days *of completing Part 5.1*.”

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

Please consider aligning the format of PRC-002-4 into the most recent version of NERC Drafting Team Reference Manual Version 4, chapter 10. For example, documents such at the Implementation Guidance and Technical Rationale are both referenced in a Section G of this Reliability Standard, but the Reference Manual states these documents should be in Section E: Associated Documents.

Additionally, the Compliance language in Section C does not appear to be the most up-to-date language. The most up-to-date language should be used in the revised Reliability Standard.

Likes 0	
Dislikes 0	

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric

Answer	
Document Name	

Comment

DTE supports NAGF's comment.

Likes 0	
Dislikes 0	

Response

Josh Combs - Black Hills Corporation - 3

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

LaKenya VanNorman - LaKenya VanNorman On Behalf of: Carl Turner, Florida Municipal Power Agency, 5, 3, 4, 6; Chris Gowder, Florida Municipal Power Agency, 5, 3, 4, 6; Dan O'Hagan, Florida Municipal Power Agency, 5, 3, 4, 6; Jade Bulitta, Florida Municipal Power Agency, 5, 3, 4, 6; - LaKenya VanNorman, Group Name Florida Municipal Power Agency (FMPA) and Members

Answer	
Document Name	

Comment

It is not clear why the Glencoe Light SAR was drafted independently from the IRPTF SAR, when both were approved at the same time. Some degree of communication of the SDT's plan would be beneficial. Since the proposed changes here are administrative, while the IRPTF's changes are more technical, we believe the Glencoe SAR should not be rushed or pushed through before the IRPTF SAR changes, and if this is a needed change, we welcome details or an explanation if this is only being balloted to get industry input on this issue, but ultimately no new revision will be pushed through until both SARs are addressed.

There has been a widespread problem with R1 of this standard requiring far too many entities to be “notified”, which has been an issue for many years. In some regions, only a notification has been required to “remote joint owners”, which was an administrative inconvenience (notification was required but the remote joint owner was not required to do anything with that information and was not required to capture any data). In other regions, the “remote joint owner” has apparently been interpreted to be required to capture data – getting back to the inference that receiving a notification under R1.2 somehow conveyed compliance responsibility to the recipient of the notification. The way the standard is written is too complex for a simple issue. Substations have buses and terminal equipment. When we identify a bus, we want voltage measurements on the bus itself, SER on the breakers to the terminal equipment, and FR of the flows on the terminals at that bus location. You can't make measurements without owning PTs, CTs, and relaying or DFR equipment. We suggest that we stop sending notifications to entities who don't own equipment within the substation or who own terminal equipment that isn't required to capture data (as per R3), and let's stop requiring “double-ended” FR and SER data. The problem is using “BES

Element" without any clarification. That term has been interpreted to mean the "entire element", and not just the portion that makes up the terminal at the substation.	
Likes 0	
Dislikes 0	
Response	
James Mearns - James Mearns On Behalf of: Dennis Sismaet, Northern California Power Agency, 4, 6, 3, 5; Jeremy Lawson, Northern California Power Agency, 4, 6, 3, 5; Marty Hostler, Northern California Power Agency, 4, 6, 3, 5; Michael Whitney, Northern California Power Agency, 4, 6, 3, 5; - James Mearns, Group Name NCPA HQ	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	

OPG supports NPCC Regional Standards Committee’s comments.	
Likes 0	
Dislikes 0	
Response	
Michael Jones - National Grid USA - 1	
Answer	
Document Name	
Comment	
Please consider organizing the sections of PRC-002-4 into the normal organization for reliability standards: Section A - Introduction, Section B - Requirements and Measures, Section C - Compliance, Section D - Regional Variances, Section E - Associated Documents. Please see the Drafting Team Reference Manual.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 5 - WECC	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	

MISO supports comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC).

In R5, Part 5.3, a new requirement was added for the RC to notify appropriate entities if a BES Element is no longer required to provide DDR data. This goes beyond the scope of the SAR; although the RC may notify parties when certain data is not needed, there is no reliability need or benefit for making this notification a requirement. Requirements 5.1 and 5.2 provide non-exclusive criteria for determining DDR locations; an RC may identify other DDR needs. An RC must have the authority to dictate where it needs data recorders and the triggers for recording data. Since R 5.4 requires this to be evaluated every five years, there is no need to further obligate the RC to notify when DDR data is not needed. Therefore, the language, "If the owner of a BES Element is no longer required to have DDR data, notify the owner within 90 calendar days" should be stricken.

This recommendations aligns with scope of the Standards Efficiency Review (SER) Project as it seeks to reduce regulatory obligations that are not essential for reliability and reduce compliance burden.

- **Overall SER Project Scope**
  - Evaluate NERC Reliability Standards using a risk-based approach to identify potential efficiencies through retirement or modification of Reliability Standard Requirements. Considering that many Reliability Standards have been mandatory and enforceable for 10+ years in North America, this project seeks to identify potential candidate **requirements that are not essential for reliability, could be simplified or consolidated, and could thereby reduce regulatory obligations and/or compliance burden**.

Likes 0	
Dislikes 0	

Response

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC 2022

Answer	
Document Name	

Comment

In R5, Part 5.3, a new requirement was added for the RC to notify appropriate entities if a BES Element is no longer required to provide DDR data. This goes beyond the scope of the SAR; although the RC may notify parties when certain data is not needed, there is no reliability need or benefit for making this notification a requirement. Requirements 5.1 and 5.2 provide non-exclusive criteria for determining DDR locations; an RC may identify other DDR needs. An RC must have the authority to dictate where it needs data recorders and the triggers for recording data. Since R 5.4 requires this to be evaluated every five years, there is no need to further obligate the RC to notify when DDR data is not needed. Therefore, the language, "If the owner of a BES Element is no longer required to have DDR data, notify the owner within 90 calendar days" should be stricken.

Likes 0	
Dislikes 0	

Response

Glenn Pressler - CPS Energy - 1,3,5

Answer	
Document Name	

Comment

Technical Reference Comments

• “Due to the loop created by Line 36 and Line 57, FR data is required for these lines and SER data is required on circuit breakers 3 and 5”

o Do not disagree that this should be recorded, but not clear from standard and Glossary of Terms that this is a requirement. The Transmission Line definition is fairly vague and neither the glossary of terms or this standard makes clear that a loop suddenly makes these lines transmission lines needing FR versus the example with the singular line. If these lines (36 & 57) were really short, we probably would have considered generator feeds versus lines.

• Rationale for Requirement R2

o Would be helpful to have diagrams showing what breakers feeding elements need and do not need SER or a more detailed statement – for example: Reactor banks, Capacitor banks, Station Service feed at power plant, Reactors off Auto Tertiary windings, etc. The “and” in the standard is something to take notice

• For faults on the interconnection to generating facilities, it is sufficient to have fault current data from the Transmission station end of the interconnection. “Current contribution from a generator can be readily calculated if needed”.

o Not sure if second sentence of this statement is true since for multiple generators you can only calculate the total of the generators and not each generator which the statement seems to imply

• Rationale for Requirement R4

o One suggestion would be to point out the need to capture the final cycle of the fault as seen by the fault recorder which can require the need to capture when current/voltage elements drop-out and not just pick up (for longer faults)

Likes 0	
Dislikes 0	

Response