Comment Report

Project Name:	2021-04 Modifications to PRC-002 | Draft 2
Comment Period Start Date:	9/26/2022
Comment Period End Date:	11/10/2022
Associated Ballots:	2021-04 Modifications to PRC-002 | Draft 1 Implementation Plan AB 2 OT 2021-04 Modifications to PRC-002 | Draft 1 PRC-002-4 | Non-binding Poll AB 2 NB 2021-04 Modifications to PRC-002 | Draft 1 PRC-002-4 AB 2 ST

There were 46 sets of responses, including comments from approximately 89 different people from approximately 63 companies representing 8 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
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Shari Heino	Brazos Electric Power Cooperative, Inc.	5	Texas RE
					David Hartman	Arizona Electric Power Cooperative, Inc.	1	WECC
					Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
DTE Energy - Detroit Edison Company	Karie Barczak	3,4,5	RF	DTE Energy	patricia ireland	DTE Energy	4	RF
					Adrian Raducea	DTE Energy - Detroit Edison Company	5	RF
					Karie Barczak	DTE Energy - Detroit Edison Company	3	RF
MRO	Kendra Buesgens	1,2,3,4,5,6,7	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
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF

					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
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
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Matt Harward	Southwest Power Pool Inc	2	MRO
					Brett Springfield	Southwest Power Pool Inc.	2	MRO
Tim Kelley	Tim Kelley		WECC	SMUD / BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC

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

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

The Standard Drafting Team (SDT) should consider combining Parts 1.1 and 1.3 (retiring Part 1.3). The SDT should consider whether “fault” should be capitalized in R1, Part 1.1, since it is a defined term in the NERC Glossary of Terms Used in Reliability Standards and is capitalized in Attachment 1. A possible rewording for Part 1.1:

“1.1. Identify BES buses for which sequence of events recording (SER) and **F**ault recording (FR) data is required by using the methodology in PRC-002-4, Attachment 1. **After the initial performance, re-evaluate all BES buses at least once every five calendar years.**”

If Part 1.3 is retired / combined into Part 1.1, then the proposed edit to Attachment 1, Step 7 should also be modified. It could be revised to “During re-evaluation per Requirement R1, **Part 1.1**, if the three phase short circuit…”.

R1, Part 1.2, as proposed in Draft 2 doesn’t seem to require the Transmission Owner to inform “other owners of BES Elements directly connected to those BES buses” if a BES Element identified in a prior performance of Part 1.1 is not identified as requiring SER or FR data as part of a re-evaluation. This could potentially result in a misinformed PRC-002 compliance obligation to the other owners of those BES Elements. A possible rewording for Part 1.2:

“1.2. Notify the other owners of BES Elements directly connected to those BES buses, that SER or FR data is required for those BES Elements **(or determined not to be required upon a re-evaluation)**, only if the Transmission Owner who identified the BES buses in Part 1.1 does not have SER or FR data. This notification is required within 90 calendar days of completion of Part 1.1.”

For footnote 1 (page 3 of the Draft 2 “clean” version), we recommend that “elements” be capitalized since it is capitalized within R1 (part 1.2) and is a defined term in the NERC Glossary of Terms Used in Reliability Standards.

The SDT should consider adding a footnote that identifies the initial effective date of PRC-002-2, R1 (7/1/2016). For Transmission Owners that have maintained their registration as a TO continuously since before 7/1/2016, this is the date that their initial performance of R1 was required.

Likes 0	
Dislikes 0	
Response	
John Daho - MEAG Power - 1 - SERC	
Answer	Yes
Document Name	
Comment	

MEAG Power agrees with revising R1 but further clarification is needed for 1.2 as shown in the technical Rationale. Below is suggested language:-
1.2.1 “Notify the other owners of BES Elements directly connected to those BES buses, that SER or FR data is required for those BES Elements”

1.2.2 "SER or FR data is only required if the Transmission Owner who identified the BES buses in Part 1.1 dos not have SER/or FR data for the BES Elements it doesn't own.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
No 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 agrees with the revisions.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	

Constellation has no comments. Kimberly Turco, on behalf of Constellation Segements 5 and 6	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy asks the DT for clarification on R1.3. Per R1.3, would notification be required every five years if the other owner was notified previously. If the other owner was notified previously and the data is currently being monitored, would notification still be required?	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Constellation has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes

Document Name	
Comment	

Minnkota supports comments submitted by the MRO NERC Standards Review Forum.

Likes 0	
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	Yes
Document Name	
Comment	

None

Likes 0	
Dislikes 0	
Response	

Leslie Hamby - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF

Answer	Yes
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 would like to highlight 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	

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	Yes

Document Name	
Comment	
Texas RE recommends Footnote 1 be revised to capitalize “elements” as it is a defined term in the NERC Glossary. The Technical Rationale document does capitalize the term.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI agrees with the changes made to Requirement 1 and the associated subparts and is sufficient to clarify when SER and FR notifications are made to “other owners” of BES Elements where SER and FR data is required.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The MRO NSRF has no comments.	
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	
Provides notification clarification and lessens duplication in FR/SER data collection implementation.	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1 - WECC	
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	

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

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

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alice Wright - Arkansas Electric Cooperative Corporation - 4 - MRO,SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5 - RF, Group Name DTE Energy	
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	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
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	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	
BC Hydro supports the revisions to Requirement R1 as proposed in Draft 2 of PRC-002-4. BC Hydro however is not supportive of the addition of the wording "under its purview" within Requirement R5 Part 5.4 of proposed PRC-002-4, and recommends that this wording be replaced with "within its Reliability Coordinator Area." BC Hydro acknowledges the SDT's response to industry comments on Draft 1 to clarify that "under its purview" and "within its RC Area" have the same intended meaning and BC Hydro supports this interpretation. However, the wording "within its RC Area" is being consistently used in several other Reliability Standards (e.g. IRO-008, IRO-009, IRO-002, IRO-010, IRO-014, IRO-017, FAC-011, FAC-014, COM-001, EOP-006, EOP-010, EOP-011) and helps differentiate from wording such as "its Wide Area", which has a different meaning. Therefore, BC Hydro believes that using the "within its RC Area" reinforces consistency across Reliability Standards and adds clarity that will alleviate the risk of possible misinterpretations. BC Hydro also recommends that the Technical Rationale document be updated to explain this change to the wording of the Requirement R5.	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5 - NPCC	
Answer	
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	

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

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	
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	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments, **and additionally OPG suggests the following modification**: "R13…If the equipment was installed prior to the effective date of this standard **or prior to the 5year re-evaluation/notification of newly identified BES Elements for which DDR is required,** and is not capable of continuous recording, triggered records must meet the following:…" The above proposed wording will allow the entities identified, part of a 5year re-evaluation/notification, as owning BES Elements for which DDR is required, to use the already existing installed equipment albeit installed after the effective date of this standard and prior to the 5year re-evaluation/notification.	

Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5 - NPCC	
Answer	No
Document Name	
Comment	

OPG supports NPCC Regional Standards Committee's comments, **and additionally OPG Suggests the following modification**:

"R13…If the equipment was installed prior to the effective date of this standard **or prior to the 5year re-evaluation/notification of newly identified BES Elements for which DDR is required,** and is not capable of continuous recording, triggered records must meet the following:…"

The above proposed wording will allow the entities identified, part of a 5year re-evaluation/notification, as owning BES Elements for which DDR is required, to use the already existing installed equipment albeit installed after the effective date of this standard and prior to the 5year re-evaluation/notification.

Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1 - WECC	
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	
Robert Follini - 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	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	Yes
Document Name	
Comment	
We agree but it must respect Requirement R8 that says that if the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, we can use the existing equipment with the triggers of the 8.1 and 8.2.	
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	
Provides implementation clarification to the ongoing re-evaluation and following R1 part 1.3 notification.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The MRO NSRF has no comments.	

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

The SDT should consider additional edits to R13, Part 13.1 to clarify applicability. A possible rewording for Part 13.1:

"13.1. Within three (3) calendar years of completing a re-evaluation **under Requirement 1, Part 1.1 (TO)** or receiving notification under Requirement R1, **Part 1.2 (TO or GO)**, have SER or FR data as applicable for BES Elements directly connected to the identified BES buses."

The SDT should also consider possible mis-interpretations of "three (3) calendar years". Based on the *ERO Enterprise CMEP Practice Guide: Implementation of "Annual" and "Calendar Month(s)" in the Reliability Standards* (dated April 19, 2019), a Calendar Year is considered as "beginning on January 1 and ending on December 31". If a notification is received in December, would the second calendar year begin on the adjacent January? The SDT should consider changing this to "within 36 calendar months".

Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

EEI supports the implementation plan being included in Requirement R13 given this is an ongoing requirement.

Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 5	
Answer	Yes
Document Name	

Comment	
We agree but it must respect R8 that says that if the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, we can use the existing equipment with the triggers of R8.1 and R8.2.	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
SIGE supports moving the timeframe from the implementation plan to Requirement R13; however, SIGE recommends that the implementation period be amended to “five (5) calendar years”. 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	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	

Comment	
Minnkota supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP thanks the Standards Drafting Team for their consideration of AEP's previous comments, and in changing from a "three year" period of time to have data in response to notification(s) under R1 to a "three calendar year" period under the proposed R13.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Moving the new SER, FR, or DDR element timetable from the Implementation Plan to the standard requirements is the appropriate location.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	

Moving the new SER, FR, or DDR element timetable from the Implementation Plan to the standard requirements is the appropriate location. Kimberly Turco, on behalf of Constellation Segements 5 and 6	
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 agrees with locating the Implementation Plan information within Requirement R13 and the clarification it is 3 calendar years.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Josh Combs - Black Hills Corporation - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Jennifer Bennett, Salt River Project, 3, 5, 1, 6; Mathew Weber, Salt River Project, 3, 5, 1, 6; Sarah Blankenship, Salt River Project, 3, 5, 1, 6; Timothy Singh, Salt River Project, 3, 5, 1, 6; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
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	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5 - RF, Group Name DTE Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alice Wright - Arkansas Electric Cooperative Corporation - 4 - MRO,SERC	
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	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Goi, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD / BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
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	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Daho - MEAG Power - 1 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy suggests the time-based requirements in R13.1 and R13.2 be increased from three calendar years to five calendar years. There are multiple challenges to implementing a transmission project within a three-year time period, the most prominent being that it could impact the scheduling and implementation of projects underway pursuant to compliance with other standards (e.g., TPL-001). Additionally, Duke Energy operates on a 3-year budget cycle, and a three calendar year requirement would present scheduling issues at the back end of the budget cycle. A five calendar year requirement would eliminate these scheduling and implementation challenges.	
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 wishes to thank the Standard Drafting Team (SDT) for their effort and inclusion of our and others' earlier comments in this draft..	
Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
Constellation has no additional comments.	

Kimberly Turco, on behalf of Constellation Segements 5 and 6

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	
Constellation has no additional comments	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	
Document Name	
Comment	

While AEP agrees in principle with the overall efforts of the Standards Drafting Team, we would like to once again express our concern regarding the associated Technical Rationale document. As we shared in our previous comments, Technical Rationale documents are only to assist in the technical understanding of a requirement and/or Reliability Standard, and should not include compliance examples or compliance language. As previously stated, AEP believes the examples provided in the proposed Technical Rationale document (especially on pages 4 through 15) go beyond mere technical understanding of the obligations and could possibly be referenced in the 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."

In future revisions of PRC-002 (i.e. outside of the current project phase), it may be worth considering the following…

1) Generator Owners could benefit from guidance within the standard regarding the thresholds in Step 7 of Attachment 1 and in clearly understanding when those have been met. When these obligations were originally developed, the "top 10 percent" methodology was a sound place to begin, but going forward, more flexibility in this regard would certainly be beneficial.

2) Develop clarity within the standard regarding re-evaluations that result in a site(s) no longer being in scope. Specifically, exactly how much time must pass until those sites may be considered no longer PRC-002 reportable?

Likes 0	
Dislikes 0	

Response

Bret Galbraith - Seminole Electric Cooperative, Inc. - 6

Answer	
Document Name	

Comment

1. Requirement 1.2: The revisions appear to state that if an identifying TO currently obtains SER/FR data for another entity's BES Elements connected to the same bus, then the identifying TO is responsible for collection of data for all applicable BES Elements on that bus. If the other entity adds equipment directly connected to the same bus after the study is performed, who is responsible for collecting information for the newly added BES Elements?
2. Requirements 5.4 and 13: It's unclear what happens to past identified BES Elements when a future revision occurs. Is the entity required to maintain compliance with the past study results, what does the transition to the new BES Elements look like, how does a transition occur if there is a shared facility and one entity is collecting another entity's SER/FR or DDR data and then decides to transition out of that location?
3. Step 7, the 15% value has only two significant digits, which would allow a 15.4% value to be equal to 15%. If this is not the outcome the STD wishes, we suggest the SDT to increase the significant digits to 15.0%.
4. The technical rationale clearly states on page 5 that directly connected requires the BES Elements to share a common ground grid. Therefore, if BES Elements are on separate ground grids, by default then, they are not directly connected – is this correct?
5. If equipment is added to a bus, e.g., a bay is added to a substation (more breakers) or a bus is extended, is SER and FR data required for these BES Elements if the bus is currently identified as requiring SER/FR information or are these new BES Elements exempt until the subsequent study?
6. If two buses are modeled as a single bus pursuant to the TO's Attachment 1 process through the TO's modeling software, e.g., small generator interconnection bus connecting to existing switchyard, are both buses required to comply with SER/FR requirements if the two buses are on separate ground grids or is the TO required to model the two buses separately?
7. For Figure 5 in the technical rationale, if Breaker 3 was not on a common ground grid with Breakers 1 and 2 then Breaker 3 would be exempt – correct?
8. On page 9 in the Technical Rationale, if the TO does not want to be responsible for the compliance requirement of recording data for the GO's BES Elements, can it still notify the GO of the GO's need to collect SER/FR data? This Standard is unclear as to whether if the TO has the ability to collect data whether it now becomes the entity that must show compliance. We believe that the owner of the equipment is required to show compliance, and how the owner does that can be through agreements as discussed in previous versions of this Standard. Is the STD now taking a different position on this issue?

9. In Figures 9 and 10 of the Technical Rationale, BES Reactors connect through Breakers M and I respectively. Both Breakers M and I are required to have SER and FR data collected, however, it does not appear that Breakers M or I are “directly connected” to the identified buses. Can the STD add additional explanation as to why these two breakers require data collection?

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	
Document Name	

Comment

BC Hydro appreciates the opportunity to comment.

For consistency and clarity (as outlined in more detail in the rationale below), BC Hydro recommends that that the wording “under its purview” be replaced with “within its Reliability Coordinator Area” within Requirement R5 Part R5.4.

Rationale:

Consistency: “within its Reliability Coordinator Area”, or very similar wording, is used in several other standards, including IRO-008, IRO-009, IRO-002, IRO-010, IRO-014, IRO-017, FAC-011, FAC-014, COM-001, EOP-006, EOP-010, EOP-011, when an RC Requirement applicability purview is only RC’s own footprint. Using terminology that is different from that used in other standards may be conducive to infer a different meaning.

Clarity: In some cases the RC has a purview that extends beyond its Reliability Coordinator Area (defined in the NERC Glossary of Terms); for example, IRO-008-2 Requirements R1 and R5 reference “its Wide Area” (also a NERC Glossary Term) to describe the RC’s obligation.

More specifically to the RC’s purview, the NERC Reliability Functional Model version 5.1 (page 30) references “Wide Area” as follows.

“The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits.”

“Thus, the Reliability Coordinator needs a “Wide Area” view that reaches beyond its boundaries to enable it to operate within Interconnection Reliability Operating Limits.”

If the SDT intended “purview” to mean “within its Reliability Coordinator Area” then this meaning could appear to be in conflict with how it is used in the functional model.

For the reasons outlined above, BC Hydro believes that using “within its Reliability Coordinator Area” instead of “under its purview” within Requirement R5 Part R5.4 will help alleviate possible misinterpretations.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	
Comment	
Minnkota supports comments submitted by the MRO NERC Standards Review Forum.	
Likes 0	
Dislikes 0	
Response	
Kenisha Webber - Entergy - NA - Not Applicable - SERC	
Answer	
Document Name	
Comment	
In regards to R1 and the bus selecting methodology, should there be an exclusion for generator collector buses, as exists in the CIP standards (i.e. CIP-002 2.4)? For example, in figure 8 from the Technical Rationale, if the same entity owns the Transmission and Generation buses, would both buses be counted as BES buses in the selecting methodology (if short circuit MVA falls within the 10 percent highest)? Is a generator collector bus, regardless of ownership, excluded from the R1 applicable BES buses?	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5 - NPCC	

Answer	
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5 - RF, Group Name DTE Energy	
Answer	
Document Name	
Comment	
none at this time	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
Clarifications provided in this revision are welcome changes. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Leslie Hamby - Southern Indiana Gas and Electric Co. - 1,3,5,6 - RF	
Answer	

Document Name	
Comment	
SIGE recommends the implementation period be amended to “five (5) calendar years”. 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	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE remains concerned that there is a risk that entities may inconsistently apply Attachment 1, which could result in improper placement of disturbance monitoring equipment and therefore inadequate disturbance analysis. Inadequate analysis may lead to risks to reliability not being properly addressed. For example, there may be a need for more buses, based on equal amounts of short circuit capability not being addressed and the interpretation of the steps. Texas RE encourages the SDT to reevaluate including changes to Attachment 1 as part of this project.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EEI again notes that 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	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
It is our opinion that the clarifications provided in this revision are welcome changes. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	

Footnote 2 in the Implementation Plan contains an error that appears to be a carryover from the Project 2015-09 Implementation Plan, which included PRC-002-3. The footnote in the Draft 2 Implementation Plan states:

PRC-002-2 and PRC-002-3, Implementation Plans: "Entities shall be 100 percent compliant with new BES [Bulk Electric System] Elements identified in Requirement R1 or R5 within three (3) years following the notification by the Transmission Operator or the Reliability Coordinator."

"Transmission Operator" should be "Transmission Owner", as PRC-002-2 nor PRC-002-3 have Transmission Operator applicability. Also, under PRC-002-2, R5 was applicable to Planning Coordinators in the Eastern Interconnection (no Reliability Coordinator applicability in the Eastern Interconnection). We suggest the footnote 2 language be modified to be relevant to the latest regulatory approved version (PRC-002-3), and the "Transmission Operator" language be corrected. Suggested rewording for footnote 2:

PRC-002-3 Implementation Plan: "Entities shall be 100 percent compliant with new BES Elements identified in Requirement R1 or R5 within three (3) years following the notification by the Transmission Owner or the Reliability Coordinator, respectively."

NERC should determine if a corrected/errata version of the Project 2015-09 Implementation Plan needs to be submitted to the appropriate governmental approval authority.

Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6,7 - MRO, Group Name MRO NSRF	
Answer	

Document Name	
Comment	
The last page contains a High Level Requirement Overview for each requirement, and R5 was not changed. However, the MRO NSRF requests the STD clean up a discrepancy within this table in the final draft of PRC-002-4. Section 4, Applicability, only includes the RC, TO, and GO. However, this table lists the "RE (PC | RC)" as the applicable entity for R5. Please revise this to RC only.	
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	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	
Answer	
Document Name	
Comment	
Recommend: The GO's and TO's shall retain evidence for six calendar years or since last audit period, whichever is shorter.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	
Document Name	

Comment	
SPP recommend that the drafting team remove the Regional Entity (RE) and Planning Coordinator (PC) from the Requirement R5 section of the High Level Requirement Overview. Currently, this section of the standard does not align with the Functional Entities of the document. In an addition to, Requirement R5 language in the standard is only applicable to the Reliability Coordinator (RC).	
Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	
No additional comments	
Likes 0	
Dislikes 0	
Response	

Comments received from Ruida Shu/NPCC RSC

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

   ☐ Yes
   ☐ No

   Comments:

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

   ☐ Yes
   ☐ No

   Comments: We agree but it must respect R8 that says that if the equipment was installed prior to the effective date of this standard and is not capable of continuous recording, we can use the existing equipment with the triggers of the 8.1 and 8.2.

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

   Comments:
   Data Retention: Recommend: The GO's and TO's shall retain evidence for six calendar years or since last audit period, whichever is shorter.

Please considering updating section C. Compliance to use the most up-to-date version of the NERC wording for section C. Compliance. The wording used in Section C. Compliance, for draft 2 of PRC-002-4, is obsolete.