Survey Report

Survey Details

Name 2007-06 System Protection Coordination | PRC-027-1 & PRC-001-1.1 (ii)

Description

Start Date 7/29/2015

End Date 9/11/2015

Associated Ballots

2007-06 System Protection Coordination PRC-027-1 & PRC-001-1.1(ii) Non-Binding Poll AB 2 NB

2007-06 System Protection Coordination PRC-027-1 & PRC-001-1.1(ii) AB 2 ST

Survey Questions

1. The term "entity-designated" and its associated footnote were removed and replaced by "Attachment A." Attachment A lists the Protection System functions applicable in the standard. Do you agree that Attachment A includes the Protection System functions that must be reviewed to maintain Protection System coordination when Fault current levels change? If not, please provide the basis for your disagreement and any proposed revisions.

Yes

No

2. Do you agree with the proposed Implementation Plan? If not, please provide the basis for your disagreement and your proposed revisions.

3. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

Responses By Question

1. The term "entity-designated" and its associated footnote were removed and replaced by "Attachment A." Attachment A lists the Protection System functions applicable in the standard. Do you agree that Attachment A includes the Protection System functions that must be reviewed to maintain Protection System coordination when Fault current levels change? If not, please provide the basis for your disagreement and any proposed revisions.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eric Schwarzrock - Berkshire Hathaway - NV Energy - 5 -

Selected Answer: No

Answer Comment:

- Attachment A does not list bus differential protection as an applicable protection function. Bus protection designed using either overcurrent, percentage differential or high impedance differential protection use a sum of currents to detect a bus fault. In an ideal world an increase in fault current would not affect the differential relays, but there are situations where an increase in fault current can negatively affect the differential relays and affect the coordination between bus differential and line relays.
    - Overcurrent and percentage differential relays are usually applied on busses where fault currents are low enough so that CT saturation does not occur. As fault currents increase, the

chances of CT saturation increase which can cause false bus differential operations for external line faults.

  - High impedance differential relay voltage settings are calculated based on the voltage that could be developed across the relay with a completely saturated CT. This voltage setting is calculated using the maximum external fault current. With increased fault currents, the voltage that could develop across the relay for a saturated CT could be higher than the voltage setting of the relay. This can also cause false bus differential operations for external line faults.

Bus differential relays should be added to Attachment A to ensure that proper coordination between bus differential relays and line relays for external faults.

Document Name:

Likes: 0

Dislikes: 0

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Northeast Utilities - 3 -

Selected Answer: Yes

Answer Comment:

We agree with the classification of specific protection system elements that require coordination. In addition, this will aid the compliance enforcement process.

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Information

Group Name: Dominion

Group Member Name	Entity	Region	Segments
Randi Heise	NERC Compliance Policy	NPCC	5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6
Chip Humphrey	Power Generation Compliance	SERC	5
Nancy Ashberry	Power Generation Compliance	RFC	5
Larry Nash	Electric Transmission Compliance	SERC	1,3
Candace L Marshall	Electric Transmission Compliance	SERC	1,3
Larry W Bateman	Transmission Compliance	SERC	1,3
Jeffrey N Bailey	Nuclear Compliance	SERC	5
Russell Deane	Nuclear Compliance	NPCC	5

Voter Information

Voter	Segment
Louis Slade	6
Entity	**Region(s)**
Dominion - Dominion Resources, Inc.	

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kayleigh Wilkerson - Lincoln Electric System - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeremy Voll - Basin Electric Power Cooperative - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter	Segment
John Seelke	1,3,5,6
Entity	**Region(s)**
PSEG	NPCC,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 4 PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jay Barnett - Exxon Mobil - 7 -

Selected Answer: Yes

Answer Comment:

While I agree that the functions listed are the ones that should be reviewed if fault current levels change, I disagree with using fault current as a trigger for a review *in all circumstances*. For those functions that do not require fault current or Protection System settings from other entities in order to ensure proper coordination, entities should be able to use equipment changes as a trigger for a coordination review. Equipment changes are already used as a trigger for other Reliability Standards and would allow for entities to have a single trigger for multiple Standards. This would add an additional, more cost effective option, while still ensuring Protection Systems on all BES Elements are coordinated. The SDT should include this as another option under Requirement 2 (see proposed revision below). A fault current trigger would remain for those functions that

	require fault current or Protection System settings from other entities in order to ensure proper coordination. Proposed Revision: *R2. Each TO, GO, and DP shall, for each BES Element with Protection System functions identified in Attachment A:* *Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six calendar years; or* *Option 2: . Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the Element is connected, all in a time interval not to exceed six calendar years; or,* ***Option 3: For functions that do not require Fault current or Protection System settings from other entities to ensure proper coordination, perform a PSCS prior to the implementation of new or modified Protection System settings on associated BES Elements.*** *Option 4: A combination of the above.*
Document Name:	
Likes:	0
Dislikes:	0
Joshua Andersen - Salt River Project - 1,3,5,6 - WECC	
Selected Answer:	Yes
Answer Comment:	
Document Name:	
Likes:	1 Tarantino Joe On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1, Ke
Dislikes:	0

Chris Scanlon - Exelon - 1 -

Group Information

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Voter Information

Voter	Segment
Chris Scanlon	1
Entity	**Region(s)**
Exelon	

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Spencer Tacke - Modesto Irrigation District - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Earle Saunders - Edison International - Southern California Edison Company - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Earle Saunders - Edison International - Southern California Edison Company - 6 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer: No

Answer Comment:

For the GO function, it would be helpful to include 51V-R and 51V-C as in scope relays in Attachment A. Also for GO, it would be helpful to note that 50/27 or 67 relays/protective functions used in generator inadvertent energization schemes are not in scope for PRC-027. Additionally, it's not clear if the 50 includes overcurrent elements used to supervise distance (21) elements.

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: No

Answer Comment:

Revision Requirement 1 allows us to develop a criteria for intended sequence which is good. Our only concern is if our criteria changes, there is no verbiage in the standard that allows for a phased implementation plan. One suggestion could be to give a 6 year cycle to be sure improvements are made will staying compliant to the proposed standard.

Document Name:

Likes: 0

Dislikes: 0

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer: No

Answer Comment:

See Comments from ACES

Document Name:

Likes: 0

Dislikes: 0

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer: No

Answer Comment:

See Comments from ACES

Document Name:

Likes: 0

Dislikes: 0

Joe Tarantino - Joe Tarantino On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Kevin Smith, Balancing Authority of Northern California, 1
Michael Ramirez, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Rachel Moore, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Susan Gill-Zobitz, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Tim Kelley, Sacramento Municipal Utility District, 3, 4, 6, 5, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer: No

Answer Comment:

In Attachment A, it seems that 67 elements used in communication-aided protection schemes should be applicable. If a communication-aided protecton scheme is needed for coordination with remote backup (e.g., long line adjacent to a short line, perhaps), a check may need to be performed that (for example) overreaching ground overcurrent pickups are still appropriate. Tacoma Power will not object to lowering the compliance risk by leaving these elements out of Attachment A, but Tacoma Power did want to bring this to the drafting team's attention.

In Attachment A, or in the Supplemental Material section, breaker failure fault detectors should be discussed. As with the 67 element, if a breaker failure fault detector is set too high in (for example) a ring bus, remote backup protection could operate instead of the local breaker failure. As with the 67 element, Tacoma Power will not object to lowering the compliance risk by leaving these elements out of Attachment A, but it probably should be at least discussed by the drafting team and documented somewhere to avoid confusion later when/after the standard becomes effective.

Document Name:

Likes: 0

Dislikes: 0

Glenn Pressler - CPS Energy - 1 -

Selected Answer: No

Answer Comment:

Agree with the elements listed, but I question the wording regarding the 21 elements. It sounds as if an entity simply sets this element by just taking a percent of the Positive Sequence Line impedance, even when infeed or mutuals are present (ground only), then the entity would never need to check these elements. However, if another entity does use these factors in determining settings of these elements, then that entity would be required to periodically check the settings. This seems to give a greater degree of risk for compliance failure for the entity that applies a more thorough method of setting these elements while leaving no risk to the entity that uses a simpler, less thorough setting method. Generally believe entities should be required to verify through studies that these elements will only operate for their intended zone of protection whenever infeed or mutuals are present.

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Greene - SERC - 10 - SERC

Group Information

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Paul Nauert	Ameren	SERC	1
Charlie Fink	Entergy	SERC	1
David Greene	SERC staff	SERC	10

Voter Information

Voter	Segment
David Greene	10
Entity	**Region(s)**
SERC	SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter
Colby Bellville

Segment
1,3,5,6

Entity
Duke Energy

Region(s)
FRCC,SERC,RFC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
Jonathan Hayes	Southwest Power Pool Inc	SPP	2
Robert Gray	Board of Public Utilities of Kansas City, Kansas	SPP	3
Michael Jacobs	Camstex	NA - Not Applicable	NA - Not Applicable
stephanie Johnson	Westar Energy, Inc	SPP	1,3,5,6
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter

Shannon Mickens

Segment

2

Entity

Southwest Power Pool, Inc. (RTO)

Region(s)

SPP

Selected Answer: Yes

Answer Comment:

We agree that the addition of Attachment A gives the industry guidance to some of the system functions and their applicable in this process especially, in reference to the calculation of the Fault current when conducting the Protection System Coordination Study (PSCS). Additionally, this helps the industry develop effective procedures that will increase the Reliability of the BES.

Document Name:

Likes: 0

Dislikes: 0

Gerry Adamski - Essential Power, LLC - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Guidry - Louis Guidry On Behalf of: John Lindsey, Cleco Corporation, 6, 5, 3, 1
Michelle Corley, Cleco Corporation, 6, 5, 3, 1
Robert Hirchak, Cleco Corporation, 6, 5, 3, 1
Stephanie Huffman, Cleco Corporation, 6, 5, 3, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2007-06 PRC-027-1

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1

Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Voter Information

Voter

Lee Pedowicz

Segment

10

Entity

Northeast Power Coordinating Council

Region(s)

NPCC

Selected Answer: Yes

Answer Comment:

We agree with the classification of specific Protection System components that require coordination. In addition, this will aid the compliance enforcement process. However, clarification is requested with regard to applicability of distance protection element. Does the standard apply to distance elements used solely for non-communication aided protection schemes (for example transfer trip, carrier systems) or for all distance element applications?

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kenn Backholm - Snohomish County PUD No. 1 - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3
Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer: No

Answer Comment:

Hydro One Networks Inc. agrees with the NPCC on the classification of specific protection systems that would entail protection system coordination. However, Hydro One Networks Inc.. would like to ask for clarification within Attachment 1 whether distance (21) elements within communications aided protection schemes are subject to the requirements of this standard. This is because there were conflicting responses provided by the NERC SDT during the Q&A Session held on August 25th, and by NATF during the monthly meeting call on August 27th.

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter

Carol Chinn

Segment

4

Entity

Florida Municipal Power Agency

Region(s)

Selected Answer: No

Answer Comment:

Attachment A would be a good list of items that must be reviewed if Fault current levels are expected to always increase, but not for any Fault current level change.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Alex Chua - Pacific Gas and Electric Company - 5 -

Selected Answer:

Answer Comment: Abstain

Document Name:

Likes: 0

Dislikes: 0

Matt Culverhouse - City of Bartow, Florida - 3 -

Selected Answer: No

Answer Comment:

Attachment A would be a good list of items that must be reviewed if Fault current levels are expected to always increase, but not for any Fault current level change.

Document Name:

Likes: 0

Dislikes: 0

Matt Culverhouse - City of Bartow, Florida - 3 -

Selected Answer: No

Answer Comment:

Attachment A would be a good list of items that must be reviewed if Fault current levels are expected to always increase, but not for any Fault current level change.

Document Name:

Likes: 0

Dislikes: 0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Group Information

Group Name: BC Hydro

Group Member Name	Entity	Region	Segments
Patricia Robertson	BC Hydro and Power Authority	WECC	1
Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	WECC	2
Pat G. Harrington	BC Hydro and Power Authority	WECC	3
Clement Ma	BC Hydro and Power Authority	WECC	5

Voter Information

Voter

Patricia Robertson

Segment

1

Entity

BC Hydro and Power Authority

Region(s)

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ben Li - Independent Electricity System Operator - 2 - NPCC

Group Information

Group Name: ISO/RTO Council Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Ben Li	IESO	NPCC	2
Kathleen Goodman	ISO-NE	NPCC	2
Mark Holman	PJM	RFC	2
Terry Bilke	MISO	MRO	2

Voter Information

Voter	Segment
Ben Li	2
Entity	**Region(s)**
Independent Electricity System Operator	NPCC

Selected Answer: Yes

Answer Comment:

Note: CAISO is not a party to the submission of the comments below.

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter	Segment
Pamela Hunter	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Selected Answer: No

Answer Comment:

See Section 3 below

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter

Ginette Lacasse

Segment

1,3,4,5,6

Entity

Seattle City Light

Region(s)

WECC

Selected Answer: No

Answer Comment: See general comments in #3

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ben Engelby - ACES Power Marketing - 6 -

Group Information

Group Name: ACES Standards Collaborators - PRC-027 Project

Group Member Name	Entity	Region	Segments
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5

Voter Information

Voter

Ben Engelby

Segment

6

Entity

ACES Power Marketing

Region(s)

Selected Answer: Yes

Answer Comment:

1. We agree with the removal of the term “entity-designated” and the addition of Attachment A to provide more clarity.
2. Note #2 in the attachment refers to additional details located in the supplemental information section of the standard. Once the standard is approved by FERC, only the applicability section and the requirements (and attachments that are incorporated by reference) will be enforceable. If the drafting team acknowledges that additional details are

	necessary to fully explain the attachment, then those details should be added at this stage of the development process.
Document Name:	
Likes:	0
Dislikes:	0

Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

2. Do you agree with the proposed Implementation Plan? If not, please provide the basis for your disagreement and your proposed revisions.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

yes

Document Name:

Likes: 0

Dislikes: 0

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Eric Schwarzrock - Berkshire Hathaway - NV Energy - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Selected Answer:

Answer Comment:

Yes,

SCE&G agrees with the SERC PCS committee comments: "It is our understanding that the 6-year evaluation interval begins on the enforcement date, allowing up to 6 years to complete a full system analysis. However, with this not being explicitly stated in the technical basis or implementation plan, we would recommend including that distinction in some location. "

Document Name:

Likes: 0

Dislikes: 0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:

Answer Comment:

Yes

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

AEP does not believe that 12 months is adequate for the Implementation Plan, and recommends that it be increased to 24 months, which we believe is more reasonable. The GO often relies on the TO to provide short-circuit studies, which increases the time necessary to establish the initial baseline.

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer:

Answer Comment:

The Implementation Plan should be extended to 24 months. As it stands now, entities only have 12 months after regulatory approvals to develop a process, establish Fault Current baseline, and establish a tracking tool for Fault Current baseline changes and/or periodic review

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Kenny - Northeast Utilities - 3 -

Selected Answer:

Answer Comment:

We strongly believe that 12 months is an inadequate amount of time for an entity to develop a formal documented process, establish a Fault Current baseline, and establish a tracking tool for Fault Current baseline changes and/or periodic review. We recommend that the Implementation Plan should be extended to 24 months.

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 -

Selected Answer:

Answer Comment:

Regarding Implementation Plan: NIPSCO believes 12 month implementation plan is very challenging and inadequate. NIPSCO recommends 24 months for implementation plan to allow entities sufficient time to establish resources and derive processes.

Document Name:

Likes: 0

Dislikes: 0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Information

Group Name: Dominion

Group Member Name	Entity	Region	Segments
Randi Heise	NERC Compliance Policy	NPCC	5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6
Chip Humphrey	Power Generation Compliance	SERC	5
Nancy Ashberry	Power Generation Compliance	RFC	5
Larry Nash	Electric Transmission Compliance	SERC	1,3
Candace L Marshall	Electric Transmission Compliance	SERC	1,3
Larry W Bateman	Transmission Compliance	SERC	1,3
Jeffrey N Bailey	Nuclear Compliance	SERC	5
Russell Deane	Nuclear Compliance	NPCC	5

Voter Information

Voter	Segment
Louis Slade	6
Entity	**Region(s)**
Dominion - Dominion Resources, Inc.	

Selected Answer:

Answer Comment:

The Technical Basis or Implementation Plan does not include sufficient details describing the 6 year evaluation interval. It is our understanding that this 6 year evaluation interval begins on the enforcement date allowing up to 6 years for the system analysis to be completed but this is not specifically stated so we recommend additional reference details be included to explicitly describe the Implementation times.

Document Name:

Likes: 0

Dislikes: 0

Kayleigh Wilkerson - Lincoln Electric System - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeremy Voll - Basin Electric Power Cooperative - 3 -

Selected Answer:

Answer Comment:

-

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment:

Yes

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer:

Answer Comment: Yes

Document Name:

Likes: 0

Dislikes: 0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter	Segment
John Seelke	1,3,5,6
Entity	**Region(s)**
PSEG	NPCC,RFC

Selected Answer:

Answer Comment:

No. While not “per se” an Implementation Plan issue, R2 is unclear as to when the first Protection System Coordination Study must be performed for Attachment A devices under R2. See additional comments in #3 below.

Document Name:

Likes: 4 PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer:

Answer Comment:

Yes.

1) For R2, if an entity decides to go with option 1, does it mean that the entity is not required to do a Protection System Coordination Study until 6 years from the effective date of the standard?

Document Name:

Likes: 0

Dislikes: 0

Jay Barnett - Exxon Mobil - 7 -

Selected Answer:

Answer Comment:

Agree.

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Salt River Project (SRP) has reviewed the Attachment A and has concerns with verifying a Fault Current baseline as required in R3. As this standard is written, this baseline must be created prior to the effective date of the standard. We strongly believe that 12 months is an inadequate amount of time to develop a formal documented process, establish a Fault Current baseline for thousands of relays, and establish a tracking tool for those Fault Current baseline changes and/or periodic review. We request that there be at least a 24 month implementation plan.

Document Name:

Likes: 1 Tarantino Joe On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1,
Ke

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Group Information

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Voter Information

Voter	Segment
Chris Scanlon	1
Entity	**Region(s)**
Exelon	

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Spencer Tacke - Modesto Irrigation District - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Earle Saunders - Edison International - Southern California Edison Company - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Earle Saunders - Edison International - Southern California Edison Company - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5 -

Selected Answer:

Answer Comment:

More detail is needed regarding the implementation plan dates for each of the requirements. Also, required dates for R2 should address Options 1 and 2 individually.

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

No; it would be helpful if the Implementation Plan included information on what is required on the effective date of the standard. There is clarifying text on page 7 of the RSAW that states what is required by the effective date of the standard, this could be included in the Implementation Plan.

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer:

Answer Comment:

We do not agree with the proposed implementation plan. For larger entiites with assets in all regions, a 12-month implementation is a challenge. 24-months would be more appropriate without taking on risk.

Document Name:

Likes: 0

Dislikes: 0

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer:

Answer Comment:

No, See comments from ACES

Document Name:

Likes: 0

Dislikes: 0

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer:

Answer Comment:

See Comments from ACES

Document Name:

Likes: 0

Dislikes: 0

Joe Tarantino - Joe Tarantino On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Kevin Smith, Balancing Authority of Northern California, 1
Michael Ramirez, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Rachel Moore, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Susan Gill-Zobitz, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Tim Kelley, Sacramento Municipal Utility District, 3, 4, 6, 5, 1

Selected Answer:

Answer Comment:

SMUD Supports Salt River Project comments.

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer:

Answer Comment:

There are no possible answers listed on this question to choose from (see attached screenshot), however, ITC Holdings would select 'YES' as an answer to this question.

Document Name: Question2_screenshot.pdf

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer:

Answer Comment:

It appears that, where Option 2 is selected, only the Fault current baselines need to be established prior to the effective date, not (necessarily) any Protection System Coordination Studies. Is this the drafting team's intention?

Where Option 1 is selected, what is the implementation timeframe?

Document Name:

Likes: 0

Dislikes: 0

Glenn Pressler - CPS Energy - 1 -

Selected Answer:

Answer Comment: yes, but no button.

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment: Yes

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment: Yes

Document Name:

Likes: 0

Dislikes: 0

David Greene - SERC - 10 - SERC

Group Information

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Paul Nauert	Ameren	SERC	1
Charlie Fink	Entergy	SERC	1
David Greene	SERC staff	SERC	10

Voter Information

Voter	Segment
David Greene	10
Entity	**Region(s)**
SERC	SERC

Selected Answer:

Answer Comment:

It is our understanding that the 6-year evaluation interval begins on the enforcement date, allowing up to 6 years to complete a full system analysis. However, with this not being explicitly stated in the technical basis or implementation plan, we would recommend including that distinction in some location.

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter

Colby Bellville

Segment

1,3,5,6

Entity

Duke Energy

Region(s)

FRCC,SERC,RFC

Selected Answer:

Answer Comment:

Based on our concerns regarding R1, subpart 1.2, as outlined in question 3, Duke Energy cannot agree to the proposed Implementation Plan. If the standard were to be approved as written, the expectation to review the developed Protection System settings, depending on the level of detail expected for the review, would take a significant amount of time to achieve compliance. For larger entities, with a great deal of applicable relays, additional resources would most definitely be required, and time to acquire and train those resources would be necessary. We do not feel the 12 months is an adequate amount of time to achieve compliance with the standard as written.

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
Jonathan Hayes	Southwest Power Pool Inc	SPP	2
Robert Gray	Board of Public Utilities of Kansas City, Kansas	SPP	3
Michael Jacobs	Camstex	NA - Not Applicable	NA - Not Applicable
stephanie Johnson	Westar Energy, Inc	SPP	1,3,5,6
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter	Segment
Shannon Mickens	2
Entity	**Region(s)**
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer:

Answer Comment:

We agree with the proposed Implementation Plan. In our opinion, the footnote provides the industry a clear and concise objective pertaining to both projects and their dependence on the success of the proposed retirement of PRC-001-1-1 (ii).

Document Name:

Likes: 0

Dislikes: 0

Gerry Adamski - Essential Power, LLC - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Louis Guidry - Louis Guidry On Behalf of: John Lindsey, Cleco Corporation, 6, 5, 3, 1
Michelle Corley, Cleco Corporation, 6, 5, 3, 1
Robert Hirchak, Cleco Corporation, 6, 5, 3, 1
Stephanie Huffman, Cleco Corporation, 6, 5, 3, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer:

Answer Comment: Yes

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2007-06 PRC-027-1

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1

Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Voter Information

Voter	Segment
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer:

Answer Comment:

Checked--No

As it stands now, entities will not have adequate time, within 12 months, to develop a process, establish Fault current baselines, and establish a tracking tool for Fault current baseline changes and/or periodic review. We recommend that the Implementation Plan be extended to 24 months.

We recommend the implementation plan include a statement clarifying the start date of the 6 year cycle that is described in Requirement R2. Is it the date the standard is effective, or the date the protection system was last reviewed prior to the effective date?

Document Name:

Likes:	0
Dislikes:	0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC **Selected Answer:** **Answer Comment:** Yes. **Document Name:** **Likes:** 0 **Dislikes:** 0
Rachel Coyne - Texas Reliability Entity, Inc. - 10 - **Selected Answer:** **Answer Comment:** Texas RE agrees with the proposed Implement Plan. **Document Name:** **Likes:** 0 **Dislikes:** 0
Kenn Backholm - Snohomish County PUD No. 1 - 6 - **Selected Answer:** **Answer Comment:** Public Utility District No. 1 of Snohomish County supports Salt River Project comments. **Document Name:** **Likes:** 0 **Dislikes:** 0

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3
Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer:

Answer Comment:

Hydro One Networks Inc. does not agree with the Implementation Plan as it is unreasonable to implement a process and establish a fault current baseline within 12 months. Further, the Implementation Plan of 12 months borders on the Long-term Planning horizon in requirement R1 itself. The NERC definition of a Long-term Planning horizon is “a planning horizon of one year or longer”. Therefore, Hydro One Networks Inc. agrees with the NPCC, and recommends that the Implementation Plan be extended from 12 months to 24 months.

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter

Carol Chinn

Segment

4

Entity

Florida Municipal Power Agency

Region(s)

Selected Answer:

Answer Comment:

Yes

Document Name:

Likes:	0
Dislikes:	0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment: Texas RE agrees with the proposed Implementation Plan.

Document Name:

Likes: 0

Dislikes: 0

Alex Chua - Pacific Gas and Electric Company - 5 -

Selected Answer:

Answer Comment: Abstain

Document Name:

Likes: 0

Dislikes: 0

Matt Culverhouse - City of Bartow, Florida - 3 -

Selected Answer:

Answer Comment: Yes

Document Name:

Likes: 0

Dislikes: 0

Matt Culverhouse - City of Bartow, Florida - 3 -

Selected Answer:

Answer Comment: Yes

Document Name:

Likes: 0

Dislikes: 0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Group Information

Group Name: BC Hydro

Group Member Name	Entity	Region	Segments
Patricia Robertson	BC Hydro and Power Authority	WECC	1
Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	WECC	2
Pat G. Harrington	BC Hydro and Power Authority	WECC	3
Clement Ma	BC Hydro and Power Authority	WECC	5

Voter Information

Voter

Patricia Robertson

Segment

1

Entity

BC Hydro and Power Authority

Region(s)

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Ben Li - Independent Electricity System Operator - 2 - NPCC

Group Information

Group Name: ISO/RTO Council Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Ben Li	IESO	NPCC	2
Kathleen Goodman	ISO-NE	NPCC	2
Mark Holman	PJM	RFC	2
Terry Bilke	MISO	MRO	2

Voter Information

Voter	Segment
Ben Li	2
Entity	**Region(s)**
Independent Electricity System Operator	NPCC

Selected Answer:

Answer Comment:

NO.

The Implementation Plan should be extended to 24 months. As it stands now, entities only have 12 months after regulatory approvals to develop a process, establish Fault Current baseline, and establish a tracking tool for Fault Current baseline changes and/or periodic review.

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter

Pamela Hunter

Segment

1,3,5,6

Entity

Southern Company - Southern Company Services, Inc.

Region(s)

SERC

Selected Answer:

Answer Comment:

Yes.

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Selected Answer:

Answer Comment:

SCL does not have issues with this aspect. However, other utilities have expressed a concern about needing more time so it may be worthwhile re-evaluating the scope for implementation plan.

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Yes.

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter

Ginette Lacasse

Segment

1,3,4,5,6

Entity

Seattle City Light

Region(s)

WECC

Selected Answer:

Answer Comment:

Yes we have no issues but we have heard others are concerned that they will need more time.

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

If a utility is in the position to leverage a tool such as CAPE or ASPEN to automate its settings review, then the proposed implementation plan seems feasible. If a utility does not have a software tool in place, then developing and tracking the settings review may require significant resources. This may actually detract from a utility's ability to create and review relay settings.

Document Name:

Likes: 0

Dislikes: 0

Ben Engelby - ACES Power Marketing - 6 -

Group Information

Group Name: ACES Standards Collaborators - PRC-027 Project

Group Member Name	Entity	Region	Segments
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5

Voter Information

Voter

Ben Engelby

Segment

6

Entity

ACES Power Marketing

Region(s)

Selected Answer:

Answer Comment:

We agree with the implementation plan that both standards (PRC-027-1 and TOP-009-1) must reach industry consensus before they are presented to the NERC Board for adoption.

Document Name:

Likes:	0
Dislikes:	0

Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4 -

Selected Answer:

Answer Comment:

yes

Document Name:

Likes: 0

Dislikes: 0

3. If you have any other comments that you haven’t already provided in response to the above questions, please provide them here.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

none

Document Name:

Likes: 0

Dislikes: 0

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Portland General Electric Company (PGE) thanks you for the opportunity to comment on this standard. PGE's System Protection group finds the proposed standard to be generally acceptable. We would, however, request that the drafting team review part 2 of PRC-023-3 Attachment A and consider exclusion of the relay elements listed in 2.1 from the requirement of PRC-027.

Document Name:

Likes: 0

Dislikes: 0

Eric Schwarzrock - Berkshire Hathaway - NV Energy - 5 -

Selected Answer:

Answer Comment:

- Option 2 of R2 is meant to allow an entity to periodically check for a 15 percent of greater deviation in fault current. This option allows the entity to choose an interval of up to six calendar years to perform the fault current comparisons (this comes from the PRC-027-1 supplemental material). Option 2 is worded in a confusing manner so that the intent is not immediately clear without reading the supplemental material.

- Attachment A lists the protection system functions applicable to R2 including: 67 – AC directional overcurrent if used in a **non-communication-aided protection scheme**. This is probably ok if the fault current increases. If the fault current decreases, then any 67 relays used in a communication-aided protection scheme might not work correctly. If the 67 element were set to overreach the other end of the line for a POTT scheme (similar to using a zone 2 element in a POTT scheme) and the fault current decreased, it's possible that the 67 element might now see faults at a maximum distance less than the distance of the line. This would render the POTT scheme not as effective since the element used to trigger the scheme does not see the entire line.

Option 2 states that a protection coordination study should be performed when a 15 percent or greater deviation in fault current is identified. A 15 percent decrease in fault current should warrant a re-study of directional overcurrent elements used in communication aided protection scheme.

Document Name:

Likes: 0

Dislikes: 0

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Selected Answer:

Answer Comment:

SCE&G agrees with the SERC PCS committee comments: "

Comments:

1) page 4, Please revise the Purpose and Facilities to clarify the scope.

a) Purpose: "To maintain the coordination of Protection Systems installed to protect detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults."

b) Facilities: "Protection Systems installed to detect and isolate Faults on protect BES Elements."

Also see comment #3 below. There are a large number of DP-TO interfaces and clarity on this interface is needed.

2) page 6 Rationale Option 2: augment ‘Planners and Planning Coordinators’ with ‘Transmission Owner’ so it reads "The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Owners, Transmission Planners, or Planning Coordinators." This makes it consistent with R1 1.1 itself, page 14 explanation.

3) page 13 DP Applicability is explained by ‘A Distribution Provider may provide an electrical interconnection and path to the BES for generators that will contribute current to Faults that occur on the BES. If the Distribution Provider owns Protection Systems that operate for those Faults, it is important that those Protection Systems are coordinated with other Protection Systems that can be impacted by the current contribution to the Fault of Distribution Provider.’ A) In the vast majority of cases fault current contributions from DP networks are quite weak, usually the last to trip, and insignificant to BES coordination. B) BES Phase 2 Definition excluded networks below 50kV and at the least this should be acknowledged here. C) PRC-027-1 Draft 6 Applicability language is consistent with the PRC-005-2 language, for which PRC-005-2 Supplement states: "‘…that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).’ The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection System **protecting** that Element should then be included within this standard." D) Add language similar to B and C in the PRC-027-1 Supplemental Material.

	4) page 17 second option: Please clarify the Fault current location for the 15% deviation trigger is the BES bus. This will help the GO and DP understand their responsibility. Please insert BES before Element in this sentence "The second option allows the entity to periodically check for a 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at each bus to which an a BES Element is connected. The drafting team intends for the 100kV or above BES bus to be the Fault current location."
Document Name:	
Likes:	0
Dislikes:	0

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:	
Answer Comment:	n/a
Document Name:	
Likes:	0
Dislikes:	0

Thomas Foltz - AEP - 5 -

Selected Answer:	
Answer Comment:	AEP supports R1 & R3. AEP believes it is reasonable to have a process to develop Protection System settings for all BES elements, and to implement that process. AEP is willing to accept the inclusion of all BES protection systems in these requirements. AEP does not support R2 as written in draft 6. AEP believes R2 should be limited to protection systems applied on BES Elements that electrically join Facilities

owned by separate functional entities. It is reasonable to require a periodic review, as prescribed in R2, on protection systems applied to interconnecting elements, because an entity does not have knowledge of what changes are made by another entity that may affect protection system coordination.

AEP believes that R1 is sufficient to cover coordination of all internal protection systems. AEP has an existing process to review area coordination when system changes are made. All settings in the area that are affected by the change are reviewed and revised as necessary. Because of this process, it is not likely that any fault current comparisons would identify a 15% deviation at any buses. Thus, this requirement would become an administrative burden without any reliability benefit for internal protection systems.

AEP proposes that R2 be changed to read:
R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers) with Protection System functions identified in Attachment A:

While AEP is supportive of the overall intent and direction of PRC-027-1, we have chosen to vote negative driven by our objections to R2, as stated above.

Document Name:

Likes: 0

Dislikes: 0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer:

Answer Comment:

the HIGH VRF for Requirement R3 seems too high since failing to meet R1 (to develop the process for developing new and revised Protection System settings for BES Elements) has a MEDIUM VRF; failing to utilize this process should not have a VF that’s higher than not having the process in place to begin with.

Document Name:	
Likes:	0
Dislikes:	0
John Fontenot - Bryan Texas Utilities - 1 -	
Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0
Mark Kenny - Northeast Utilities - 3 -	
Selected Answer:	
Answer Comment:	1. We suggest that the drafting team consider the potential overlap of PRC-027-1 R1.1.1 and MOD-032-1, R1 and provide necessary clarification in the supplemental material. 2. R2, Option 2 has two actions associated with it, both of which have to be completed in one timeframe. The two actions are the fault current comparison against the baseline and the performance of a Protection System Coordination Study if the fault current comparison exceeds 15% or greater deviation. It is recommended that under this option, if an entity identifies a 15% or greater deviation in fault current value at a bus, the entity is given a set amount of time per element to complete a protection coordination study on all applicable elements at that bus.

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

ReliabilityFirst agrees that PRC-027-1 helps to alleviate the risk of insufficient coordination of Protection Systems installed to detect Faults on BES Elements and isolate those faulted Elements (such that the Protection Systems operate in the intended sequence during Faults). ReliabilityFirst offers the following comments related to the term "coordination" for the Standard Drafting Team's consideration:

1. **ReliabilityFirst notes that the term "coordination" used in Requirement 1, Parts 1.3.2 and 1.3.3 is not defined within PRC-027-1 or the NERC Glossary Terms. This term is also used within a number of other Reliability Standards where it is likewise undefined. As a result, and according to FERC precedent, the dictionary definition of the term "coordination" will control. As a result, the term "coordination" could reasonably be interpreted to refer to either the setting of Protection Systems *or* to communications between entities.**

To add clarity to PRC-027-1, ReliabilityFirst recommends replacing the term "coordination" with the term "Protection System Coordination." Listed below is ReliabilityFirst's proposed NERC Glossary definition of "Protection System Coordination" for the Standard Drafting Team's consideration:

Protection System Coordination **- The setting of Protection Systems installed for the purpose of detecting and isolating Faults on BES Elements, such that the Protection Systems operate in a defined sequence in an effort to remove such Faults from the BES.**

1. **ReliabilityFirst recommends the following changes to Requirement 1, Parts 1.3.2 and 1.3.3 to incorporate this new definition of "Protection System Coordination" (highlighted in red below):**

1.3.2. Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any Protection System Coordination Issue(s) or affirming that no Protection System Coordination issue(s) were identified.

1.3.3. Verify that identified Protection System Coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.

Document Name:

Likes: 0

Dislikes: 0

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 -

Selected Answer:

Answer Comment:

Regarding R2: NIPSCO believes that measurement criteria M2 for Protection System Coordination Studies (PSCS) is not very clear. Standard needs to provide a clear direction as to what is considered an acceptable form of evidence for PSCS.

Document Name:

Likes: 0

Dislikes:	0

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Information

Group Name: Dominion

Group Member Name	Entity	Region	Segments
Randi Heise	NERC Compliance Policy	NPCC	5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6
Chip Humphrey	Power Generation Compliance	SERC	5
Nancy Ashberry	Power Generation Compliance	RFC	5
Larry Nash	Electric Transmission Compliance	SERC	1,3
Candace L Marshall	Electric Transmission Compliance	SERC	1,3
Larry W Bateman	Transmission Compliance	SERC	1,3
Jeffrey N Bailey	Nuclear Compliance	SERC	5
Russell Deane	Nuclear Compliance	NPCC	5

Voter Information

Voter	Segment
Louis Slade	6
Entity	**Region(s)**
Dominion - Dominion Resources, Inc.	

Selected Answer:

Answer Comment:

- Comments: Section R1.1: Consider adding additional clarity to the sub-requirement to limit the review to the modified BES Elements or BES Elements in the zone of protection. For example, the statement could be modified as follows: “A review and update of short circuit models for the modified BES Elements under study or BES Elements in the zone of protection.” This limits the scope of the short circuit model review to just the elements being studied.

Document Name:

Likes:	0
Dislikes:	0

Kayleigh Wilkerson - Lincoln Electric System - 5 -

Selected Answer:

Answer Comment:

LES suggests that the evidence required to meet R3 be limited and clearly defined. As currently drafted, the scope of potential evidence to demonstrate compliance with R3 would be difficult to anticipate and therefore unmanageable. Recommend the evidence be limited to entities providing short-circuit model updates (R1.1), Protection System setting reviews (R1.2), and Protection System setting coordination between owners for electrically-joined Facilities (R1.3).

LES recommends Option 2 of R2 be further clarified. It is not clear if a Protection System Coordination Study is required even if a fault current baseline hasn't deviated by 15% in 6 years. Additionally, it is also not clear what the scope of the Protection System Coordination Study is. To provide further clarity to R2 Option 2, LES suggests modifications similar to the following:

Compare present Fault current values to an established Fault current baseline in a time interval not to exceed six calendar years. A Protection System Coordination Study must be performed on the Elements connected to the bus where the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground). This Protection System Coordination Study must be completed within one calendar year of the Fault current comparison. The Fault current baseline will be updated to the present Fault current values only on the Elements for which the Protection System Coordination Study was performed.

Additionally, LES recommends protection system functions that are only enabled when other relays or associated systems fail be excluded from the R2 (e.g., overcurrent elements that are only enabled during loss of potential conditions). We feel that these protection system functions are used only as a contingency and should not fall within scope of the standard.

Document Name:

Likes: 0

Dislikes: 0

Jeremy Voll - Basin Electric Power Cooperative - 3 -

Selected Answer:

Answer Comment:

The BEPC believes that the same applicability exclusion used for PRC-001-1.1 (ii) or PRC-005 should be applied to PRC-027. The key is coordination at the overall wind farm interface after the power has been aggregated. Without this exclusion, the burden of the standard outweighs any reliability benefits provided.

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Information

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Voter Information

Voter	Segment
Emily Rousseau	1,2,3,4,5,6
Entity	**Region(s)**
MRO	MRO

Selected Answer:

Answer Comment:	The NSRF believes that the same applicability exclusion used for PRC-001-1.1 (ii) or PRC-005 should be applied to PRC-027. The key is coordination at the overall wind farm interface after the power has been aggregated. Without this exclusion, the burden of the standard outweighs any reliability benefits provided. The DGR applicability exclusion from PRC-001-1.1 (ii) should be added to R2, R3 or to Attachment A. FERC would not let a current requirement go unaddressed. Similarly, the individual generator exclusion from PRC-001-1.1 (ii) cannot be ignored. As an example, the following could be added to either a requirement or Attachment A: • Requirement R2 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition. The exclusion is required to address the blanket inclusion of individual wind turbines under the new Bulk Electric System (BES) definition Inclusion 4 (I4) and wording in Requirement 2 that states “each BES Element with Protection System functions identified in Attachment A” are to be addressed. Another alternative is the NSRF recommends an Applicability statement such as (PRC-005-2i): • 4.1.4 Protection Systems for the following BES generator Facilities for dispersed power producing resources identified through Inclusion I4 of the BES definition: • 4.1.4.1 Protection Systems for Facilities used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or above. The NSRF would like to see the words “NERC registered” added in front of the word “owner” to ensure that entities with multiple non-NERC joint owners avoid the unnecessary administrative burden of attempting to track entities with no NERC responsibilities. With PSE and possibly LSE deregistration, entities could be connected with non-NERC entities. The NERC paper process of exchanging information could become asymmetric as only one entity has legal requirements for actions and the other doesn’t. Adding “NERC registered” should reduce unnecessary administration and create a symmetric or level set of requirements between affected entities. In order to take advantage of Requirement R2-Option 2, a fault current baseline must be established prior to the effective date. This sets entities up for the potential to do a considerable amount of work based upon the expectation that

nothing will change between the approval date and the effective date. Given the degree of change with PRC-005, there is certainly some amount of apprehension in this regard. A better method would be to allow the entity to establish the baseline within one year after the effective date or allow a phased-in approach.

There is no requirement ensuring the Transmission Owner will share the model database or Fault current study results to allow Generation Owners and Distribution Providers to complete R2 Option 1, 2 or 3. The applicability section recognizes that the TO's are the typical entity maintaining the system model for Fault studies. NSRF prefers previous draft versions that required the TO to conduct fault studies on all buses, make comparisons and notify other entities if the fault current changed.

The 6-year frequency requirement could be relaxed to be more consistent with other relay maintenance activities or there should be more justification provided for the additional cost of more frequent analysis.

Document Name:

Likes: 0

Dislikes: 0

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Information

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Voter Information

Voter	Segment
John Seelke	1,3,5,6
Entity	**Region(s)**
PSEG	NPCC,RFC

Selected Answer:

Answer Comment:

We have separately submitted a Word redline with comments. However, PSEG's comments are summarized below. We would vote "Affirmative" if the SDT adopted the changes proposed in PSEG's redline.

- We propose that the SDT modify the definition of Protection System Coordination Study by limiting it to Protection Systems for BES Elements.

- We propose that the SDT add "Transmission Planner" to the Functional Entities in Section 4.1. This change is consistent with proposed changes to delete R1.1 and add R4 so that the Transmission Planner performs Fault current studies and makes them available to their TOs, GOs, and DPs in R4. As we note in the rationale for R4:

"Transmission Planners develop short circuit data bases per MOD-032-1 and utilize them in TPL-001-4 to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt. Since Transmission Planners develop and use short circuit databases, having other entities (TOs, GOs and DPs) use them could introduce errors. Therefore, Transmission

Planners should be required to calculate all Fault current values for its busses (an initial baseline and subsequent periodic updates) and make those available to its Transmission Owners, Generator Owners, and Distribution Providers."

- In R2, we eliminated the footnote in Option 2 because proposed R4 will result in an initial Fault current baseline established by the TP on or before the effective date of the standard. Given this, when would an entity's first PSCS need to be performed for its Attachment A devices under R2? For example, if Option 2 is selected, is the first PSCS required when the baseline fault current increases by 15 percent or greater?

- Other changes in language in R1, R2, and R3 are explained in comments in the redline.

Document Name: pseg redline of PRC-027-1_Draft_6_09.09.15.docx

Likes: 4

PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla

Dislikes: 0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Selected Answer:

Answer Comment:

(1) Please address each of our following comments as many of them were not addressed in the last ballot action. If these comments are not addressed, Seminole may revise its ballot vote from affirmative to negative upon the next ballot action.

(2) This Standard references the terms “BES Elements.” In reviewing the NERC Glossary, there are many references to merely “Elements” without the preceding “BES” adjective, i.e., Remedial Action Scheme definition. What is the difference between “BES Elements” and “Elements” (without the BES)? Is the term “Element” without BES reference to elements that are non-BES, and if that is the case, does subpart “e.” of the RAS definition apply to non-BES Elements as there is no preceding “BES”? “BES Elements” and “Elements” are still both utilized in the Standard. Per discussions with the drafting team, it was stated that this is accidental and that there is no difference and that the team will clean these up to merely state “Elements” in the next version.

(3) In R2, if a review was performed on March 1, 2017 and an entity had 6 calendar years in which to complete the review, is that 6 full calendar years? Meaning, would an entity not have to complete another review until December 31, 2023? Could you please include the above example, or an example akin to the above in the guidelines as we want to confirm we understand that 6 full calendar years are allowed, which means that more than 72 months between tests could be taken under certain timing circumstances?

(4) In R1 Part 1.5.3, this Requirement merely states that the coordination issues need to be “addressed” prior to implementation. We have two questions on this requirement, the first being that after reviewing the supplemental guidance material, that under certain circumstances, such as where additional system modifications are needed, that such modifications do not need to take place before the settings changes if the entity didn’t originally place those modifications into the scope of the settings changes project. Because the Requirement does not require the modifications to take place in any future time, can the drafting team describe in more detail how these issues are “addressed prior to implementation”? In discussions with the drafting team regarding what “addressed” means is that any coordination issues need to be agreed upon between the entities and the entities must agree to the implementation actions and a timeframe for implementation, and depending on the circumstances,

"outstanding" updates can be implemented after implementation of proposed Protection System changes. Please confirm that this is correct.

(5) In the Supplemental Material section, there are references to the terms "BES Protection System" and "Protection System." The Standard applies to "Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted elements." For purposes of this Standard, is a BES Protection System a Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted elements? There are still references to "BES Protection System" and "Protection System." In discussions with the drafting team it was noted that all of these references were going to be cleaned up to merely state "Protection System". Please confirm.

(6) In Requirement R1, is the 15% value 15.% with two significant figures in that if we have a deviation of 14.6% we need to perform an evaluation as it rounds up to 15% or are there more significant figures, i.e., 15.0%? This was discussed again with the drafting team that our comment wasn't answered in the guidance, but per a phone conversation it was stated that anything above 15.000000000 (infinity) is a violation. We'd prefer the NERC drafting teams begin honoring significant digits as it's not a difficult clarification and it makes compliance problematic because we can't tell if it's intentional or not when the drafting teams stop at a certain point. Therefore, this request is still out there, please place as many digits the team feels is significant as we will keep making this comment on every future drafted Standard, e.g., is 15.000% enough for the drafting team?

(7) In Requirement R2, if an entity uses the time based option and uses a recent short-circuit study for its baseline study, does the 6-year option 2 time frame start from the time of enforcement of the Standard or from the date the short-circuit study was finalized? The answer to this question does not appear to be in the Requirement. For Option 2, per our discussion, if a Protection System Coordination Study is performed today, the 6 year timeframe doesn't begin until the enforcement date of the Standard, correct? We are still somewhat unclear as to when the Fault current baseline comparison needs to be performed however. For example, does a Fault current baseline need to be performed every 6 years? There is some language in the Rationale box on this issue, but that language says "may" and not "shall" so it appears this isn't a requirement but merely a suggestion

(8) "Electrically joined Facilities" is not defined. Per past discussions, the intent appears to be to describe Facilities that are electrically joined AND are physically joined. Meaning, that if one Facility is 10 miles down the transmission line from another Facility, albeit "electrically joined" by electrons moving through both Facilities, the Facilities are not physically touching, and therefore, not covered by the intent of "electrically joined Facilities" under this Standard. Is this correct?

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer:

Answer Comment:

1) Manitoba Hydro suggests that the title of this standard is changed from "Coordination of Protection Systems for Performance During Faults" to: "Protection System Coordination Performance During Faults"

2) For section 1.3.4.2, "Misoperation investigation" may be better replaced by "Protection System operation investigation"

3) For R2, there seems to be no incentive (nor requirement) for entities to go with option 2 since they still have to do this study within 6 years regardless the level of fault current changes anyway.

Document Name:

Likes: 0

Dislikes: 0

Jay Barnett - Exxon Mobil - 7 -

Selected Answer:

Answer Comment:

The Supplemental Material states, "The Transmission Owner, which is typically the entity maintaining the system model for Fault studies, will provide the Fault current availability upon request by the Distribution Provider or Generator Owner," however, there is nothing in the draft of PRC-027-1 that requires this and that would ensure this is done in a timely manner. This draft might introduce the circumstance where the GO has the responsibility to periodically compare data that the TO has and maintains. The Standard should require TOs to respond to GO requests for Fault current data in a timely manner so that the GO can perform coordination studies if necessary. Another approach would be to transfer the responsibility of performing the periodic comparisons to the TOs. If the fault current changed by 15%, then the TO would notify the affected GO so that a coordination study would be performed. The same issue would exist for small TOs that do not maintain wide-area system models.

Proposed Revision:

R2.1. Upon discovery of a change in Fault current of a BES Element owned by another GO, TO, or DP, each TO shall provide the updated Fault current values to the affected owners within 90 calendar days of discovery.

OR

R2.1. Each TO that maintains Fault current values for BES Elements owned by other GOs, TOs, or DPs, shall respond to requests for such information from the GO, TO, or DP within 90 calendar days.

Also, Requirement 3 should be limited to the attributes listed in Requirement 1 in order to have a clear and consistent measure for compliance. As written, auditors would have to become familiar with each entity's entire coordination process in order to determine compliance. Instead each entity should only have to demonstrate compliance with those attributes which the Standard Drafting Team has determined are "must have" to ensure proper coordination, as described in Requirement R1.

Proposed Revision:

R3. Each TO, GO, and DP shall utilize a process that contains the minimum attributes established in Requirement R1 to develop new and revised Protection System settings for BES Elements.

Document Name:

Likes: 0

Dislikes: 0

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

Salt River Project (SRP) has concern over R1 part 1.1 and 1.2. As written, R1 calls for a “process for developing new and revised Protection System settings”. Parts 1.1 and 1.2 requires a “review and update of short-circuit models” and a “review of the developed Protection System settings”, respectively. The process defined in R1 should not have to include either review. SRP recommends changing part 1.1 and 1.2 to reflect “A methodology to evaluate ...”. In previous conversations with the SDT NERC staffer, it was communicated that the intent of this requirement was to include a methodology, however the previous draft removed the language that would have signified a methodology was required. If the intent is that a process rather than the actual review is included, it should read as such.

Document Name:

Likes: 1 Tarantino Joe On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1,
Ke

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Group Information

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Voter Information

Voter	Segment
Chris Scanlon	1
Entity	**Region(s)**
Exelon	

Selected Answer:

Answer Comment:

The applicability of the standard needs to be clarified so that dispersed resources at the individual resource prior to the point of aggregation are not subject to the standards requirements. In the transition from PRC-001.1ii., the exclusion for dispersed resources appears to have been improperly dropped from PRC-027-1. The PRC-027-1 mapping document lists PRC-001.1ii R3.1 and the dispersed resources sub-bullet exclusion but we cannot find a record indicating that there was discussion resulting in a deliberate intent to remove the exclusion in the transition from PRC-001.1ii to PRC-027-1. While a change to applicability prior to a final ballot is considered a substantive change in Section 4.14 of Standards Process Manual, we note that per the same section, "Where there is a question as to whether a proposed modification is "substantive," the Standards Committee shall make the final determination". We therefore request that the SDT bring this issue to the Standards Committee for consideration and include the dispersed generation exclusion in PRC-001.1ii in PRC-027-1 prior to final ballot.

Other options to address this concern could include, clarification in the Supplementary Material section, notes to auditors in the RSAW or the submission by the SDT of a SAR to change the applicability consistent with the dispersed generator exclusion as currently included in PRC-001-1ii .

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Selected Answer:

Answer Comment:

We would like to see an exception for distributed resources similar to what project 2014-01 is working on for other standards. Typically distributed resources do not look out to the transmission system, but unless they are excluded this will need to be examined and documented.

Document Name:

Likes: 0

Dislikes: 0

Spencer Tacke - Modesto Irrigation District - 4 -

Selected Answer:

Answer Comment:

Hi,

I really believe the time period options for doing a Protection Coordination Study specified in R2 (Option 1 or Option 2) are much too large. When I used to attend the WECC Meetings on a regular basis, I remember how a high percentage of the major system outages were tied to mis-coordination or mis-operation of the protective relay systems of the various neighboring utilities. As the member’s protection systems are critical to the reasonable reliability of the interconnected system, waiting six years to do another fault current check for the 15% threshold is unreasonable, or allowing no threshold current check but with a fixed 6 year time period between coordination studies, is asking for trouble. I would strongly support a one year period as the required time to do a new Protection System Coordination Study for each member's BES. Remember, NERC requires annual Transmission Planning Assessments (TPL Standards), so we should not accept any lower of a standard for a Protection System Coordination Study. Thank you.

Sincerely,

Spencer Tacke

Senior Electrical Engineer

Modesto Irrigation District

	209-526-7414 spencert@mid.org .
Document Name:	
Likes:	0
Dislikes:	0

Earle Saunders - Edison International - Southern California Edison Company - 6 -

Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Earle Saunders - Edison International - Southern California Edison Company - 6 -

Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5 -

Selected Answer:

Answer Comment:

It appears that if Option 1 is selected for R2, an entity has six years from the effective date to complete the study and also evidence for R3 would not be required until this same date. Please confirm.

Functional Entities, under Applicability and each requirement, should include Transmission Planners.

Document Name:

Likes: 0

Dislikes: 0

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP

Selected Answer:

Answer Comment:

Option 2 of R2 is meant to allow an entity to periodically check for a 15 percent of greater deviation in fault current. This option allows the entity to choose an interval of up to six calendar years to perform the fault current comparisons (this is derived from the PRC-027-1 supplemental material). The intent of Option 2 is not immediately clear without reading supplemental material. Given that compliance is measured only by the text of the requirement, R2 Option 2 should be clarified to indicate that if the 15 percent fault current baseline hasn't been exceeded, a protection coordination study isn't required even it if has been more than six calendar years.   Or is the intent of the drafting team to state that if the 15 percent baseline threshold hasn't been exceeded a coordination study isn't required?

Additionally, the evidence retention section would benefit from clarification. There could be possible confusion with the 6 year interval of the standard versus a possible audit interval of 3 years.

Another opportunity for improvement would be to align the intervals with the intervals identified in PRC-019, which would be beneficial to GOs.

Document Name:

Likes: 0

Dislikes: 0

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer:

Answer Comment:

See Comments from ACES

Document Name:

Likes: 0

Dislikes: 0

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer:

Answer Comment:

See Comments from ACES

Document Name:

Likes: 0

Dislikes: 0

Joe Tarantino - Joe Tarantino On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Kevin Smith, Balancing Authority of Northern California, 1
Michael Ramirez, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Rachel Moore, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Susan Gill-Zobitz, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Tim Kelley, Sacramento Municipal Utility District, 3, 4, 6, 5, 1

Selected Answer:

Answer Comment:

SMUD supports Salt River Project comments.

Document Name:

Likes: 0

Dislikes: 0

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer:

Answer Comment:

In the Supplemental Material section, there are concerns about the following paragraph: “A Distribution Provider may provide an electrical interconnection and path to the BES for generators that will contribute current to Faults that occur on the BES. If the Distribution Provider owns Protection Systems that operate for those Faults, it is important that those Protection Systems are coordinated with other Protection Systems that can be impacted by the current contribution to the Fault of Distribution Provider.” If the generator is not a BES generator, or the generation plant is not a BES plant, the associated Protection Systems should not be under the purview of this standard unless, perhaps, they serve to provide a blocking signal to other Protection Systems associated with the BES Element or their clearing is necessary for the other Protection Systems associated with the BES Element to operate properly. For small non-BES generation, the Transmission Owner may configure its Protection Systems to properly respond with or without the small generator(s) connected. In these cases, clearing the generator(s) is arguably more about safety (isolating sources of energization) and not coordination.

It sounds like the only triggers for conducting a Protection System Coordination Study (PSCS) are the following: (1) triggered by Requirement R2, (2) triggered by the need to establish a baseline for Requirement R2 for new BES Elements or new BES Facilities, or (3) triggered by the need to establish a baseline for Requirement R2 when transitioning between Options 1 and 2. Otherwise, if there are Protection System changes, or if there are changes to existing BES

Elements, it sounds like a PSCS is not (necessarily) required, provided that the other elements identified in Requirement R1 are addressed. Is this the drafting team’s intention? If a PSCS will be required for other cases, this should be more clearly identified.

The verbiage in Requirement R2, Option 2, is a little unclear. For example, if Fault current values are compared within four calendar years, and the percentage change is less than 15%, does this reset the maximum six calendar year interval under Option 2?

Under Requirement R1, Part 1.3.4, Tacoma Power suggests appending "…scenarios such as the following:"

The Rationale for Requirement R1 includes a note about internal documentation. Tacoma Power had hoped that documentation would not explicitly be required in a scenario in which one engineering workgroup is responsible for Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities, especially when those functional entities are part of the same company/organization. There is concern about the amount of extra documentation that may be involved. Furthermore, when different functional entities are part of the same company/organization, it may not be 100% clear where the DP vs. TO or TO vs. GO line should be drawn; by contrast, the same internal documentation would not be required for internal TO-TO interaction.

The emphasis of this standard should only be to show that there is not miscoordination. It is a little awkward, but Tacoma Power suggests that the Purpose statement could be reworded to the following (CAPS added to identify suggested rewording): "To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems DO NOT operate in the UNintended sequence during Faults." Similarly, the definition of a PSCS could be reworded to the following: "An analysis to determine whether Protection Systems DO NOT operate in the UNintended sequence during Faults." Requirement R1 could be reworded to the following: "...such that the Protection Systems DO NOT operate in the UNintended sequence during Faults..."

Compared to Requirement R1, Tacoma Power is not convinced that the justification has been made for a High VRF for Requirement R3. Failing to implement one piece of the process established under Requirement R1, even for one BES Element, coupled with no graduated VSLs (see subsequent comment), would result in the maximum potential penalty.

Tacoma Power believes that the drafting team should leverage the Lower, Moderate, and High VSLs for Requriement R3. FERC's VSL G1 only states that the VSL assignment should not have the UNINTENDED consequence of lowering the current level of compliance. Furthermore, the scope of applicability of PRC-027-1 is much greater than PRC-001-1, so it is reasonable for PRC-027-1 to leverage the Lower, Moderate, and High VSLs, even though PRC-001-1 did not.

An example of a Protection System Coordination Study in the Supplemental Material section might be helpful.

Document Name:

Likes: 0

Dislikes: 0

Glenn Pressler - CPS Energy - 1 -

Selected Answer:

Answer Comment:

R1 – Generally think there should be a bit more detail or definiation provided to "Protection System settings" that require reviewing. Does this just include element set values? Or does it also include logic settings? Drawings versus output contact programming? What about communications equipment? Keeping this wide open and letting entities define goes back down the PRC-005-1 road where some entities had much higher testing and maintenance standards, but were also held to that higher standard and punished harshly when even falling just short.

R2 – Generally believe that giving the option of using fault studies or a time interval is for determining when to review coordination in R2. However, believe that if using the baseline fault studies, then the entity should have a shorter period between performing such studies. One issues with the baseline fault studies is that coordination studies may go for an additional 6 years, even if the 6 year study shows the fault current at just below the 15% threshold. I believe a 3 year or 4 year interval would be more reasonable. Otherwise, why not just use the baseline method since it too is on a 6 year interval.

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment:

Reclamation suggests that the drafting team reorder R2 and R3 for clarity. This would allow the standard to follow a logical order requiring an entity to have a system protection coordination process (R1), follow it (R2), and periodically update system protection coordination studies for functions in Attachment A (R3).

Reclamation also suggests that the drafting team update R1.3.4 to clarify that communications resulting from unforeseen circumstances may be “after-the- fact notifications” rather than requiring advance communication. This would clarify that Protection System owners do not need to wait for confirmation from owners of electrically-joined Facilities before revising Protection System settings due to unforeseen circumstances. Reclamation believes that waiting for coordination with owners of electrically joined facilities in these situations could increase risks to BES reliability from faulty Protection System settings that are discovered during commissioning, misoperation investigations, and maintenance or component failures which should be addressed immediately. Reclamation suggests that this should be clear in the requirement itself, not merely mentioned in the supplemental material.

Finally, Reclamation suggests that the drafting team update M3 to provide examples of how an entity would demonstrate that it is following the process required by R1 to include more detail regarding example evidence to show compliance with each subrequirement.

Document Name:

Likes: 0

Dislikes: 0

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment:

Reclamation suggests that the drafting team reorder R2 and R3 for clarity. This would allow the standard to follow a logical order requiring an entity to have a system protection coordination process (R1), follow it (R2), and periodically update system protection coordination studies for functions in Attachment A (R3).

Reclamation also suggests that the drafting team update R1.3.4 to clarify that communications resulting from unforeseen circumstances may be “after-the- fact notifications” rather than requiring advance communication. This would clarify that Protection System owners do not need to wait for confirmation from owners of electrically-joined Facilities before revising Protection System settings due to unforeseen circumstances. Reclamation believes that waiting for coordination with owners of electrically joined facilities in these situations could increase risks to BES reliability from faulty Protection System settings that are discovered during commissioning, misoperation investigations, and maintenance or component failures which should be addressed immediately. Reclamation suggests that this should be clear in the requirement itself, not merely mentioned in the supplemental material.

Finally, Reclamation suggests that the drafting team update M3 to provide examples of how an entity would demonstrate that it is following the process required by R1 to include more detail regarding example evidence to show compliance with each subrequirement.

Document Name:

Likes: 0

Dislikes: 0

David Greene - SERC - 10 - SERC

Group Information

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Paul Nauert	Ameren	SERC	1
Charlie Fink	Entergy	SERC	1
David Greene	SERC staff	SERC	10

Voter Information

Voter
David Greene

Segment
10

Entity
SERC

Region(s)
SERC

Selected Answer:

Answer Comment:

1) page 4, Please revise the Purpose and Facilities to clarify the scope.
a) Purpose: “To maintain the coordination of Protection Systems installed to protect Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate
in the intended sequence during Faults.”
b) Facilities: “Protection Systems installed to protect BES
Elements.”

Also see comment #3 below. There are a large number of DP-TO interfaces and clarity on this
interface is needed.

2) page 6 Rationale Option 2: augment ‘Planners and Planning Coordinators’ with ‘Transmission
Owner’ so it reads “The Fault current baseline values can be obtained from the short-circuit
studies performed by the Transmission Owners, Transmission Planners, or Planning Coordinators.”
This makes it consistent with R1 1.1 itself, page 14 explanation.

3) page 13 DP Applicability is explained by ‘A Distribution Provider may provide an electrical
interconnection and path to the BES for generators that will contribute current to Faults that
occur on the BES. If the Distribution Provider owns Protection Systems that operate for those
Faults, it is important that those Protection Systems are coordinated with other Protection Systems
that can be impacted by the current contribution to the Fault of Distribution Provider.’ A) In
the vast majority of cases fault current contributions from DP networks are quite weak, usually the
last to trip, and insignificant to BES coordination. B) BES Phase 2 Definition excluded networks

below 50kV and at the least this should be acknowledged here. C) PRC-027-1 Draft 6 Applicability language is consistent with the PRC-005-2 language, for which PRC-005-2 Supplement states: "'…that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).' The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection System protecting that Element should then be included within this standard." D) Add language similar to B and C in the PRC-027-1 Supplemental Material.

4) page 17 second option: Please clarify the Fault current location for the 15% deviation trigger is the BES bus. This will help the GO and DP understand their responsibility. Please insert BES before Element in this sentence "The second option allows the entity to periodically check for a 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at each bus to which a BES Element is connected. The drafting team intends for the 100kV or above BES bus to be the Fault current location."

Document Name:

Likes: 0

Dislikes: 0

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Information

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Voter Information

Voter

Colby Bellville

Segment

1,3,5,6

Entity

Duke Energy

Region(s)

FRCC,SERC,RFC

Selected Answer:

Answer Comment:

Upon our review of the most recent draft of the proposed PRC-027-1 standard, we have significant concerns regarding the expectations outlined in R1, subpart 1.2. In part 1.2, the applicable Functional Entity is required to conduct or ensure some type of review is done on its Protection System settings. While the latitude that is given to the industry on how and what type of review they are to implement is recognized, we feel that specifically mandating a quality review is unnecessary. The requirement of ensuring that quality reviews are executed is not currently included in other Protection and Control standards, and is not mandated in other standard families (with the exception of CIP-014). We do not disagree with the practice of quality assurance, however, we do not support the practice of requiring an entity to do so in a Reliability Standard. Duke Energy recommends the removal of subpart 1.2 from R1.

Document Name:

Likes: 0

Dislikes: 0

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Information

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
Jonathan Hayes	Southwest Power Pool Inc	SPP	2
Robert Gray	Board of Public Utilities of Kansas City, Kansas	SPP	3
Michael Jacobs	Camstex	NA - Not Applicable	NA - Not Applicable
stephanie Johnson	Westar Energy, Inc	SPP	1,3,5,6
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5

Voter Information

Voter	Segment
Shannon Mickens	2

Entity	Region(s)
Southwest Power Pool, Inc. (RTO)	SPP

Selected Answer:

Answer Comment:

We have a concern about the mentioning of the Transmission Planner and Planning Coordinator in the Requirement R2 Rationale Box and those entities performing the calculations for the Fault current through short circuit analysis. The Rationale Box for Requirement R2 states “The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners and Planning Coordinators”. We would suggest the removal of those entities from the Rationale Box because they aren’t include in the applicability section of the standard. Additionally, we feel that the fault current calculation has been addressed in the scope of the TPL Documentation. In that documentation, it is understood that the Transmission Planner or Planning Coordinator will conduct the fault current analysis on the BES facilities however, the Transmission Planner

	would have to coordinate with the owners and determine which protection systems would be impacted.
Document Name:	
Likes:	0
Dislikes:	0

Gerry Adamski - Essential Power, LLC - 5 -

Selected Answer:

Answer Comment:

I believe it would be appropriate to include the Transmission Planner as an applicable entity for R2 purposes as they typically maintain the fault current/short circuit values at the buses.

I had to reread R2 a couple of times to be clear that the coordination study required as part of Option 2 only applies to the buses where the deviation exceeds 15% and not required of all the buses. If an opportunity exists, a minor clarifying edit would be recommended.

in R2, the standard speaks to a deviation at a bus to which the Element is connected. Is this intended to be a bus that is part of the BES? I'm thinking of how this would be applied at a generating plant where there is the transmission voltage level bus, the generating plant bus (e.g. 18 kV), lower voltage level buses within the plant, etc. I'm wondering how this aspect would be applied in practice at a plant. Perhaps clarifying edits in the requirement language and accompanying discourse in the rationale would help clarify this…

Document Name:

Likes: 0

Dislikes: 0

Louis Guidry - Louis Guidry On Behalf of: John Lindsey, Cleco Corporation, 6, 5, 3, 1
Michelle Corley, Cleco Corporation, 6, 5, 3, 1
Robert Hirchak, Cleco Corporation, 6, 5, 3, 1
Stephanie Huffman, Cleco Corporation, 6, 5, 3, 1

Selected Answer:

Answer Comment:

The definition of Power System Coordination Study is defined as an analysis of the operating sequence. Our interpretation of the definition is that we have to model the relay action and demonstrate that it operates in the intended sequence. Cleco uses fault simulations to develop the settings. We do not model the relays in our short-circuit program to demonstrate the relay action.

2. The standard requires an internal review of the developed settings. Who is going to review the settings currently develop? Relay settings are an art due to the compromised required because of so many unique problems. No two people are going to solve the problem exactly the same. Should two people develop the settings and compare results?

3. The standard requires a review of the short-circuit model prior to developing settings. What constitutes a valid review?

4. Requirement 1.3 says we get a response from other owners prior to implementing settings on associated BES elements. How much time before Cleco responds is required? How much time do we have to wait for a response? What if neighboring entity request a response for many of our associated systems at once?

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer:

Answer Comment:

Please state that when a fault current baseline is first established we are not required to show a coordination study for every protection scheme on our system. Please state that utilities are not required to show a coordination study if the baseline continues to show a fault current change less than 15%?

Requirement R2 option 2 states “Fault current values (either three phase or phase to ground) at a bus to which the Element is connected” where the RSAW states “Fault current comparison and results for each BES Element”. The RSAW and Standard should match language as closely as possible. In this case the standard states bus faults and the RSAW evidence specifies each element which is more than just a bus. It may be wise to delay industry RSAW reviews until the standard language is in a more finalized state.

Consider adding a modification to R2. There should be an allowed time line for a coordination study to take place after the 15% fault current threshold has been identified as being exceeded. This presents a risk many could step into unwittingly when the identification is close to the 6 year interval. There are circumstances where fault currents may not change until close to this 6 year interval due to system changes that may not be foreseen. We suggest the requirement include a two year window after a 15% change is identified.

Please provide a definition or examples to clarify what is considered “electrically-joined Facilities”. For example, if a line and both terminals and protection is owned by entity A at sub 1 and sub 2. All other equipment at sub 1 is owned by entity B. All equipment at Sub 2 is owned by entity A. Is sub 2 “electrically-joined”?

The RSAW in the sections for R1 and R3 states: “In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation”. We request a provision in the Standard allowing if all separate functional entities within an organization have access to the same internal documentation, then the communication aspects are not required.

In a situation where utility A does work for another utility B on their transmission system protection equipment and utility A owns all the other surrounding protection systems, please clarify how the communication evidence would change with coordination work since utility A is making all the coordination decisions. Is it acceptable to show utility A has all utility B protection system settings internally stored? Does this make utility A responsible for utility B compliance?

For a facility that has multiple bus voltages such as 115kV, 230kV and 345kV and if the fault current baseline exceeds 15% on just the 115kV bus does this mean just the elements connected to the 115kV bus must have a coordination study but not the 230 or 345kV buses?

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer:

Answer Comment:

Please state that when a fault current baseline is first established we are not required to show a coordination study for every protection scheme on our system. Please state that utilities are not required to show a coordination study if the baseline continues to show a fault current change less than 15%?

Requirement R2 option 2 states “Fault current values (either three phase or phase to ground) at a bus to which the Element is connected” where the RSAW states “Fault current comparison and results for each BES Element”. The RSAW and Standard should match language as closely as possible. In this case the standard states bus faults and the RSAW evidence specifies each element which is more than just a bus. It may be wise to delay industry RSAW reviews until the standard language is in a more finalized state.

Consider adding a modification to R2. There should be an allowed time line for a coordination study to take place after the 15% fault current threshold has been identified as being exceeded. This presents a risk many could step into unwittingly when the identification is close to the 6 year interval. There are circumstances where fault currents may not change until close to this 6 year interval due to system changes that may not be foreseen. We suggest the requirement include a two year window after a 15% change is identified.

Please provide a definition or examples to clarify what is considered “electrically-joined Facilities”. For example, if a line and both terminals and protection is owned by entity A at sub 1 and sub 2. All other equipment at sub 1 is owned by entity B. All equipment at Sub 2 is owned by entity A. Is sub 2 “electrically-joined”?

The RSAW in the sections for R1 and R3 states: “In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation”. We request a provision in the Standard allowing if all separate functional entities within an organization have access to the same internal documentation, then the communication aspects are not required.

In a situation where utility A does work for another utility B on their transmission system protection equipment and utility A owns all the other surrounding protection systems, please clarify how the communication evidence would change with coordination work since utility A is making all the coordination decisions. Is it acceptable to show utility A has all utility B protection system settings internally stored? Does this make utility A responsible for utility B compliance?

For a facility that has multiple bus voltages such as 115kV, 230kV and 345kV and if the fault current baseline exceeds 15% on just the 115kV bus does this mean just the elements connected to the 115kV bus must have a coordination study but not the 230 or 345kV buses?

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Information

Group Name: NPCC--Project 2007-06 PRC-027-1

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1

Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Voter Information

Voter	Segment
Lee Pedowicz	10
Entity	**Region(s)**
Northeast Power Coordinating Council	NPCC

Selected Answer:

Answer Comment:

The parenthetical phrase in sub-Part 4.1.3 of the Applicability is not necessary and should be deleted. FPA 215 already ready limits the applicability of all reliability standards to the Bulk Power System and believe that NERC has revised the BES definition so that it should, either through application of bright line criteria or through the NERC or FERC exception process, encompass only those Elements and Facilities that are subject to FPA 215.

It should also be noted that, in this version the word “its” is deleted from Requirement 1 but that the Rationale for Requirement R1 uses the word “their” while Measure 1 uses the word “its”. We suggest changes be made so that all contain consistent verbiage. We believe that an entity can only be responsible for Protection System(s) it owns and would prefer this be explicitly indicated in the requirement(s).

As defined in the NERC Glossary, the Reliability Coordinator is the entity that is the highest level of authority who is responsible for the reliable operation of the

Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and Real-time operations. The Reliability Coordinator has the purview above and beyond that of a Transmission Operator that is broad enough to enable the calculation of Interconnection Reliability Operating Limits. Because new relay settings or revisions to relay settings can impact IROL calculations, the Reliability Coordinator must be aware of any new relay settings or revised relay settings in advance of their implementation.

For these reasons the standard needs to require that each Transmission Owner, Generator Owner and Distribution Provider notify the Reliability Coordinator that it is developing new or revised relay settings. The revision should also allow for the Reliability Coordinator to provide comments on the new or revised relay settings. To capture this, we suggest the following revision to R1:

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults. The process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A review and update of short-circuit models for the BES Elements under study.

1.2. A review of the developed Protection System settings.

1.3. Provide new or revised Protection System settings to the Reliability Coordinator.

1.3.1 Respond to the Reliability Coordinator’s comments regarding the proposed new or revised Protection System settings by resolving any coordination issue(s) or affirming that no coordination issue(s) were identified.

1.4. For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

1.4.1. Provide the proposed Protection System settings to the owner(s) of the electrically-joined Facilities.

Also, to clarify and reinforce the nature of the broader protection coordination concern, suggest the following modification to the Purpose:

“To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection

Systems operate in the intended sequence during Faults without causing an inadvertent adverse impact anywhere on the BES."

We suggest that the drafting team review PRC-027-1 R1 Part 1.1 and MOD-032-1, R1 for a potential overlap, and if necessary provide clarification in the supplemental material.

R2, Option 2 has two actions associated with it, both of which have to be completed in one timeframe. The two actions are the Fault current comparison against the baseline and the performance of a Protection System Coordination Study if the fault current comparison exceeds 15% or greater deviation. It is recommended that under this option, if an entity identifies a 15% or greater deviation in Fault current value at a bus, the entity is given a set amount of time per element to complete a protection coordination study on all applicable elements at that bus.

In many cases, smaller entities that are interconnected to larger TOs do not develop their own Protection System settings. These settings are provided to them by the interconnecting TO and mandated to be implemented through Interconnection agreements. R1 should be revised to recognize these instances, including the Rationale for Requirement R1 words related to a "single protective relaying group performing the work for multiple functional entities," as a single group may be responsible for the process for multiple owners of BES Elements. The note should also be included in the Requirement and Measure as internal documentation will be used to determine the coordination aspects of Part 1.3.

Requirement R3 needs a "trigger" to initiate the process described therein. Suggest revising Requirement R3 to read:

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that determines a need for new or revised Protection System settings shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements.

To avoid confusion between modeling and protection short circuit modeling, suggest adding the word "protection" to make the term used in the standard "protection short circuit".

Document Name:

Likes: 0

Dislikes: 0

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment:

N/A

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

Texas RE recommends deleting the comment regarding ownership in the Functional Entities section since there is no need with risk-based compliance.

In the Evidence Retention section, Texas RE recommends changing the statement “since the last audit” to “since the last audit of these requirements.”

Document Name:

Likes: 0

Dislikes: 0

Kenn Backholm - Snohomish County PUD No. 1 - 6 -

Selected Answer:

Answer Comment:

Public Utility District No. 1 of Snohomish County supports Salt River Project comments.

Document Name:

Likes: 0

Dislikes: 0

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3
Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer:

Answer Comment:

1) Hydro One Networks Inc. agrees with the NPCC and recommends that the NERC SDT provides clarification on the overlap of requirements between MOD-032-1, R1 (to develop short-circuit modelling data requirements) and PRC-027-1, R1 (to establish a process which includes a review and update of short-circuit models).

2) Requirement R2, Option 2, entails two actions: 1) a fault current comparison against a previously established baseline be performed, and 2) a Protection System Coordination Study be performed if the results of the comparison study exceed a deviation 15%. Presently, both these actions need to be performed within the same timeframe. However, Hydro One Networks Inc. agrees with the NPCC in that a separate time period should be allotted for an entity to complete a protection coordination study on all associa0ted elements on a bus, if a deviation of 15% or greater in the available fault current comparison is identified.

3) Further, Hydro One Networks Inc. also recommends that in the interest of clarity, the two actions within Option 2 of requirement R2 be separated out.

Document Name:

Likes:	0
Dislikes:	0

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Information

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Voter Information

Voter	Segment
Carol Chinn	4
Entity	**Region(s)**
Florida Municipal Power Agency	

Selected Answer:

Answer Comment:

1. From a standards development process perspective, FMPA recognizes that there was a fair amount of industry outreach recently on this Project. Yet, given the low results (<40%) in the prior balloting, a written “consideration of comments” would have been helpful. Plus, is it surprising that this round of questions only addresses the “Attachment A” and the “Implementation Plan” and not the actual standard language.

These few questions will not necessarily gather the input needed by the SDT, in case additional improvements are needed.

2. Requirement 1.3.4 has 4 sub parts that can drive auditors to require registered entities to prove the negative. Would suggest that the four sub parts be not listed as such and instead just be collapsed into the sentence. That will reduce the likelihood that auditors will feel compelled to ask for “specific supporting evidence to prove the negative” which we were told during outreach was not the intent of the SDT.

Part 1.3.4 *Communicate with the other owner(s) of the electrically-joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during:*

1.3.4.1. *Implementation or commissioning.*

1.3.4.2. *Misoperation investigations.*

1.3.4.3. *Maintenance activities.*

1.3.4.4. *Emergency replacements required as a result of Protection System component failure.*

3. FMPA has previously commented that the speed at which faults are cleared is very important to reliability, and does not understand why sequence is call out in the standard and associated definitions as being more important. FMPA recommends the SDT consider adding language to R1 that requires review of Protection System settings with regard to critical clearing time.

Document Name:

Likes: 0

Dislikes: 0

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment:

Texas RE recommends deleting the comment regarding ownership in the Functional Entities section since there is no need with risk-based compliance.

In the Evidence Retention section, Texas RE recommends changing the statement “since the last audit” to “since the last audit of these requirements.”

Texas RE is concerned there is no time frame for entities to provide settings or response to settings in R1.3 The implication is that setting should be provided before implementation by using the word “proposed” but R1.3.2 does not discuss any timeframe for a response. R1.3.4 does not discuss a time frame for communication of revised settings in an unforeseen circumstance.

The footnote for R2 could cause confusion. It is not clear that an Entity should not exceed six years between either performing a Study or comparing Fault current values. If an entity changes options before the six year mark, a Study should be done at that time to establish the baselines.

Texas RE recommends changing the severe VSL for R2 to “The responsible entity failed to perform Option 1, Option 2 or Option 3, in accordance with Requirement 2 for each element.”

Document Name:

Likes: 0

Dislikes: 0

Alex Chua - Pacific Gas and Electric Company - 5 -

Selected Answer:

Answer Comment: Abstain

Document Name:

Likes: 0

Dislikes: 0

Matt Culverhouse - City of Bartow, Florida - 3 -

Selected Answer:

Answer Comment:

1. From a standards development process perspective, we recognize that there was a fair amount of industry outreach recently on this Project. Yet, given the low results (<40%) in the prior balloting, a written “consideration of comments” would have been helpful. Plus, is it surprising that this round of questions only addresses the “Attachment A” and the “Implementation Plan” and not the actual standard language. These few questions will not necessarily gather the input needed by the SDT, in case additional improvements are needed.

Document Name:

Likes: 0

Dislikes: 0

Matt Culverhouse - City of Bartow, Florida - 3 -

Selected Answer:

Answer Comment:

1. From a standards development process perspective, we recognize that there was a fair amount of industry outreach recently on this Project. Yet, given the low results (<40%) in the prior balloting, a written “consideration of comments” would have been helpful. Plus, is it surprising that this round of questions only addresses the “Attachment A” and the “Implementation Plan” and not the actual standard language. These few questions will not necessarily gather the input needed by the SDT, in case additional improvements are needed.

Document Name:

Likes: 0

Dislikes: 0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Group Information

Group Name: BC Hydro

Group Member Name	Entity	Region	Segments
Patricia Robertson	BC Hydro and Power Authority	WECC	1
Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	WECC	2
Pat G. Harrington	BC Hydro and Power Authority	WECC	3
Clement Ma	BC Hydro and Power Authority	WECC	5

Voter Information

Voter	Segment
Patricia Robertson	1

Entity	Region(s)
BC Hydro and Power Authority	

Selected Answer:

Answer Comment:

The requirement to coordinate protective relay settings has existed since the first power systems were built. BC Hydro, like all utilities, has been coordinating their protection systems as part of their normal practice and has a process for setting development, review and implementation on its protection systems. While the requirements in Draft 6 of PRC-027-1 are not substantially different than standard industry practice, proving annual compliance with these requirements (to the satisfaction of lawyers) will impose a large administrative burden. The original focus of PRC-001 made sense in that there are always communications and data gathering issues that make coordinating protection systems across different utilities more challenging than coordinating within one's own system. The new draft standard focuses too much of the utility's time and effort on proving compliance on a process that typically works well, which reduces the amount of time and effort that can be spent on areas where more time and money should be spent.

Document Name:

Likes: 0

Dislikes:	0

Ben Li - Independent Electricity System Operator - 2 - NPCC

Group Information

Group Name: ISO/RTO Council Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Ben Li	IESO	NPCC	2
Kathleen Goodman	ISO-NE	NPCC	2
Mark Holman	PJM	RFC	2
Terry Bilke	MISO	MRO	2

Voter Information

Voter	Segment
Ben Li	2
Entity	**Region(s)**
Independent Electricity System Operator	NPCC

Selected Answer:

Answer Comment:

The Planning Coordinator, Reliability Coordinator, and Balancing Authority must be notified when new or revised protection settings are developed.

As defined in the NERC Glossary, the Planning Coordinator is the responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems. Because the Planning Coordinator is responsible for the coordination and integration of protection systems, it must be aware of any new relay settings or revised relay settings in advance of their implementation.

As also defined in the NERC Glossary, the Reliability Coordinator is the entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The

Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision. Because new relay settings or revisions to relay settings can impact IROL calculations, the Reliability Coordinator must be aware of any new relay settings or revised relay settings in advance of their implementation.

Finally, draft requirements in the proposed TOP-009-1 reliability standard require that the Balancing Authority ensure that "… its personnel responsible for Reliable Operation of its Balancing Authority Area have knowledge of operational functionality and effects of Composite Protection Systems and Remedial Action Schemes that are necessary to perform its Real-time monitoring in order to maintain generation-Load-Interchange balance." Accordingly, Balancing Authorities will need to be provided with new or revised Protection System settings to fulfill its obligations under TOP-009-1.

Therefore, the standard needs to require that each Transmission Owner, Generator Owner and Distribution Provider notify the Planning Coordinator, Reliability Coordinator, and Balancing Authority that it is developing new or revised relay settings. The revision should also allow for the Planning Coordinator or Reliability Coordinator to provide comments on the new or revised relay settings. To capture this, the ISO/RTO Council Standards Review Committee suggests the following revision in R1:

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults. The process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1 A review and update of short-circuit models for the BES Elements under study.

1.2 A review of the developed Protection System settings.

1.3 Provide new or revised Protection System settings to the Planning Coordinator, Reliability Coordinator, and Balancing Authority.

1.3.1 Respond to the Planning Coordinator or Reliability Coordinator's comments regarding the proposed new or revised Protection System settings.

1.4 For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

1.4.1 Provide the proposed Protection System settings to the owner(s) of the electrically-joined Facilities.

Also, to clarify and reinforce the nature of the broader protection coordination concern, the following modification to the Purpose is proposed:

"To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults without causing an inadvertent adverse impact anywhere on the BES."

Document Name:

Likes: 0

Dislikes: 0

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC

Group Information

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Voter Information

Voter	Segment
Pamela Hunter	1,3,5,6
Entity	**Region(s)**
Southern Company - Southern Company Services, Inc.	SERC

Selected Answer:

Answer Comment:

We request that the SDT consider the following changes/ clarifications:

Present language:

R1.1 A review and update of short-circuit models for the BES Elements under study.

Proposed:

R1.1 A review and update of short-circuit models or data for the BES Elements under study.

This change will address concerns from GOs and DPs that don’t have anything to do with the short-circuit model and potentially only need the fault current data at the interconnected bus from the TO.

In the rational box for **R2:**

Present language:

The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners and Planning Coordinators.

Proposed language:

The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners, Planning Coordinators or Transmission Owners.

Document Name:

Likes: 0

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Selected Answer:

Answer Comment:

SCL General Comments

1) The Option 2 baseline should include a system-wide review of the entities instantaneous overcurrent elements, that are utilized on the BES, as well as the performance of the baseline fault study.

SCL experience has demonstrated that overreaching instantaneous overcurrent elements are one of the largest causes of miscoordination in a Protective Relay System.

2) The draft Standard, in its present form, is reminiscent of the early stages of the PRC-005 (Relay Maintenance) Standard, in that each utility will establish their own implementation (issue and installation of the relay settings) schedule timeline, without any constraints. This did not work well, for Standard PRC-005 as the utilities with strong maintenance plans were scrutinized, during audits, much more rigorously than those utilities with weaker maintenance plans, even though the weaker maintenance plans made the BES less reliable. It required several revisions of the PRC-005 Standard to get everyone on the same playing field. SCL believes that a similar situation will occur if a not-to-exceed schedule timeline is not established for the implementation of the revised relay settings.

R1. - Introduction

Modify text in paragraph to read: such that the Protection Systems, associated with the protective functions listed in Attachment A, operate in the intended sequence during faults.

R1. – Add Section 1.4

Inside of this section describe the timeline allowed to implement the revised relay settings.

For example, “new and revised relay settings necessary for the coordination of the Protection Systems, associated with the protective functions listed in Attachment A, shall be issued and installed within one year after the Protection Coordination Study has been performed”.

R2. – Option 2

Modify text in paragraph to include the following steps:

1) Compare the present fault current values to the previously established fault current baseline at each BES bus within the entitiy’s system, with Protection Systems, associated with the protective functions listed in Attachment A.

2) Identify the buses where the present fault current value exceeds the baseline value by an amount that is 15%, or greater, in magnitude.

3) Perform a Protection System Coordination Study on the area of the system defined by the BES elements that are connected to the buses identified in Step 2.

4) The time interval to perform steps 1-3 shall not exceed six calendar years.

ATTACHMENT A

Modify text for relay elements as follows (line number defined at beginning of sentence):

21-1 – Zone 1 distance relay if:

• Infeed is used in determining reach (phase & ground distance), or

• zero-sequence mutual coupling is used in determining reach (ground distance)

21-2 – Zone 2 distance relay if:

• Infeed is used in determining reach (phase & ground distance), or

• zero-sequence mutual coupling is used in determining reach (ground distance)

50 – Instantaneous overcurrent

51 – AC inverse time overcurrent if used in a non-communication-assisted protection scheme.

67 I – Directional Instantaneous overcurrent

67 T – Directional inverse time overcurrent if used in a non-communication-assisted protection scheme.

SUPPLEMENTAL MATERIAL REQUIREMENTS R1

Modify the text for the last paragraph of Section R1 just above Part 1.1 to read:

The coordination of some Protections Systems may seem unnecessary, such as for a line element that is protected solely by dual current differential relays . . . with other Protection Systems of the line element such that tripping does not unnecessarily occur for faults outside of the differential zone, unless there is a Protection System failure on the adjacent line element.

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Please state that when a fault current baseline is first established we are not required to show a coordination study for every protection scheme on our system. Please state that utilities are not required to show a coordination study if the baseline continues to show a fault current change less than 15%?

Requirement R2 option 2 states “Fault current values (either three phase or phase to ground) at a bus to which the Element is connected” where the RSAW states “Fault current comparison and results for each BES Element”. The RSAW and Standard should match language as closely as possible. In this case the standard states bus faults and the RSAW evidence specifies each element which is more than just a bus. It may be wise to delay industry RSAW reviews until the standard language is in a more finalized state.

Consider adding a modification to R2. There should be an allowed time line for a coordination study to take place after the 15% fault current threshold has been identified as being exceeded. This presents a risk many could step into unwittingly when the identification is close to the 6 year interval. There are circumstances where fault currents may not change until close to this 6 year interval due to system changes that may not be foreseen. We suggest the requirement include a two year window after a 15% change is identified.

Please provide a definition or examples to clarify what is considered “electrically-joined Facilities”. For example, if a line and both terminals and protection is owned by entity A at sub 1 and sub 2. All other equipment at sub 1 is owned by entity B. All equipment at Sub 2 is owned by entity A. Is sub 2 “electrically-joined”?

The RSAW in the sections for R1 and R3 states: “In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation”. We request a provision in the Standard allowing if all separate functional entities within an organization have access to the same internal documentation, then the communication aspects are not required.

In a situation where utility A does work for another utility B on their transmission system protection equipment and utility A owns all the other surrounding protection systems, please clarify how the communication evidence would change with coordination work since utility A is making all the coordination decisions. Is it acceptable to show utility A has all utility B protection system settings internally stored? Does this make utility A responsible for utility B compliance?

For a facility that has multiple bus voltages such as 115kV, 230kV and 345kV and if the fault current baseline exceeds 15% on just the 115kV bus does this mean just the elements connected to the 115kV bus must have a coordination study but not the 230 or 345kV buses?

Document Name:

Likes: 1 Nebraska Public Power District, 1, Cawley Jamison
Nebraska Public Power District, 1, Cawley Jamiso

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Information

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Voter Information

Voter

Ginette Lacasse

Segment

1,3,4,5,6

Entity

Seattle City Light

Region(s)

WECC

Selected Answer:

Answer Comment:

SCL GENERAL COMMENTS

1) The Option 2 baseline should include a system-wide review of the entities instantaneous overcurrent elements, that are utilized on the BES, as well as the performance of the baseline fault study.

SCL experience has demonstrated that overreaching instantaneous overcurrent elements are one of the largest causes of miscoordination in a Protective Relay System.

2) The draft Standard, in its present form, is reminiscent of the early stages of the PRC-005 (Relay Maintenance) Standard, in that each utility will establish their own implementation (issue and installation of the relay settings) schedule timeline, without any constraints. This did not work well, for Standard PRC-005 as the utilities with strong maintenance plans were scrutinized, during audits,

much more rigorously than those utilities with weaker maintenance plans, even though the weaker maintenance plans made the BES less reliable. It required several revisions of the PRC-005 Standard to get everyone on the same playing field. SCL believes that a similar situation will occur if a not-to-exceed schedule timeline is not established for the implementation of the revised relay settings.

R1. - Introduction

Modify text in paragraph to read: such that the Protection Systems, associated with the protective functions listed in Attachment A, operate in the intended sequence during faults.

R1. – Add Section 1.4

Inside of this section describe the timeline allowed to implement the revised relay settings.

For example, “new and revised relay settings necessary for the coordination of the Protection Systems, associated with the protective functions listed in Attachment A, shall be issued and installed within one year after the Protection Coordination Study has been performed”.

R2. – Option 2

Modify text in paragraph to include the following steps:

1) Compare the present fault current values to the previously established fault current baseline at each BES bus within the entitiy’s system, with Protection Systems, associated with the protective functions listed in Attachment A.

2) Identify the buses where the present fault current value exceeds the baseline value by an amount that is 15%, or greater, in magnitude.

3) Perform a Protection System Coordination Study on the area of the system defined by the BES elements that are connected to the buses identified in Step 2.

4) The time interval to perform steps 1-3 shall not exceed six calendar years.

ATTACHMENT A

Modify text for relay elements as follows (line number defined at beginning of sentence):

21-1 – Zone 1 distance relay if:

• Infeed is used in determining reach (phase & ground distance), or

• zero-sequence mutual coupling is used in determining reach (ground distance)

21-2 – Zone 2 distance relay if:

• Infeed is used in determining reach (phase & ground distance), or

• zero-sequence mutual coupling is used in determining reach (ground distance)

50 – Instantaneous overcurrent

51 – AC inverse time overcurrent if used in a non-communication-assisted protection scheme.

67 I – Directional Instantaneous overcurrent

67 T – Directional inverse time overcurrent if used in a non-communication-assisted protection scheme.

SUPPLEMENTAL MATERIAL REQUIREMENT R1

Modify the text for the last paragraph of Section R1 just above Part 1.1 to read:

The coordination of some Protections Systems may seem unnecessary, such as for a line element that is protected solely by dual current differential relays with other Protection Systems of the line element such that tripping does not unnecessarily occur for faults outside of the differential zone, unless there is a Protection System failure on the adjacent line element.

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

ATC recommends revising PRC-027-1 to identify a clear connection between performance and the requirements of this standard. Where PRC-004 data provides a mechanism to measure performance, the better means to achieve reliability performance would allow each entity to use its company's misoperations data and the greater industry data to develop a program that addresses its greatest need.

Document Name:

Likes: 0

Dislikes: 0

Ben Engelby - ACES Power Marketing - 6 -

Group Information

Group Name: ACES Standards Collaborators - PRC-027 Project

Group Member Name	Entity	Region	Segments
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5

Voter Information

Voter	Segment
Ben Engelby	6
Entity	**Region(s)**
ACES Power Marketing	

Selected Answer:

Answer Comment:

1. For requirement R1, Part 1.1, the requirement states that the TO, GO, and DP must have a process to review and update short-circuit models for BES Elements under study. We disagree that the GO and DP must complete their own short-circuit models. Our recommendation is to allow GOs and DPs to use the TO's short circuit study for applicable GO or DP buses.
2. For requirement R1, Part 1.3, we disagree with the requirement of documenting internal coordination, especially considering that smaller

entities may have a single protection engineer that is responsible for completing the study. Also, we disagree that there needs to be eight sub-parts for joint ownership coordination. This is administrative in nature and burdensome for compliance. This sub-part is overly complicated and creates opportunities for entities to fall out of compliance. There is little benefit to reliability for having this much detail required.

3. For requirement R2, option 1, performing studies for all applicable relays can be resource intensive, especially for smaller entities. We recommend that the drafting team consider the Cost Effective Analysis Process (CEAP) to determine if the reliability benefits outweigh the cost of compliance.
4. For requirement R2, option 2, the baseline process is complicated. We recommend stating in footnote one that the baseline for option 2 must be completed within 12 months after the standard goes into effect. Also, the measure should state that if there is not a fault current deviation greater than 15 percent, then an attestation is sufficient evidence for compliance.
5. For requirement R2, option 3, there should be specific guidance in the measures to demonstrate compliance for the combined approach, such as a baseline for applicable distance or overcurrent relays to occur within 12 months of the effective date and a Protection System Coordination Study (PSCS) for the remaining applicable Protection Systems to occur every 6 years after the effective date.
6. For requirement R3, the documentation requirements for coordination activities of new/revised settings is administrative in nature. We question the need for an administrative documentation requirement that is assessed a high risk. Industry has long history of coordinating Protection Systems and there is not any evidence of a widespread lack of Protection System coordination. We do not see how requiring a documented process will reduce the risks to reliability. Thus, we do not see how it enhances reliability and believe it could actually detract by causing applicable entities to focus on paperwork.

Document Name:

Likes: 0

Dislikes: 0

Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4 -

Selected Answer:

Answer Comment:

FE's primary concern relates to what is required of the GO to be able to comply with R1 which states the TO, GO and DP "… establish a process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults." The GO, operates the units essentially as isolated BES elements. The term "sequence" infers it is referring to the BES as a whole, at least with regard to interconnected elements, which would then mean we need a joint process with the TO. The GO is not in a position to make that happen, nor should the GO have primary responsibility. This should be a TO responsibility, with GO providing settings as requested by TO, and GO changing settings as requested/instructed by the TO.

FE believes the TO should be identified as the entity to establish the system protection coordination and be responsible for PSCSs (Power System Coordination Studies), Fault Studies, Short Circuit Studies, etc., to prove coordination. Communication to the GO should also be the TO's responsibility. The GO would be responsible to implement setting changes as directed by the TO, where applicable and if able. The GO's connection to the BES normally ends/terminates with the Generator Step Up transformer so the GO does not have the data to perform any Power System Coordination Studies, Fault Studies, or Short Circuit Studies

Document Name:

Likes: 0

Dislikes: 0

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Description of Current Draft

The System Protection Coordination Standard Drafting Team (SPCSDT) created a new results-based standard, PRC-027-1, with the stated purpose: "To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those Faults, such that the Protection Systems operate in the intended sequence during Faults." PRC-027-1 clarifies the coordination aspects and incorporates the reliability objectives of Requirements R3 and R4 from PRC-001-1.1(ii).

Completed Actions	Date
Standard Authorization Request (SAR) posted for comment	June 11 – July 10, 2007
SAR approved	August 13, 2007
Draft 1 of PRC-001-2 posted for comment	September 11 – October 26, 2009
Draft 1 of PRC-027-1 posted for formal comment with ballot	May 21 – July 5, 2012
Draft 2 of PRC-027-1 posted for formal comment with ballot	November 16 – December 17, 2012
Draft 3 of PRC-027-1 posted for formal comment with ballot	June 4 – July 3, 2013
Draft 4 of PRC-027-1 posted for formal comment with ballot	November 4 – December 31, 2013
Draft 5 of PRC-027-1 posted for informal comment	October 1 – October 21, 2014
Draft 5 of PRC-027-1 posted for formal comment with ballot	April 1 – May 15, 2015
Draft 6 of PRC-027-1 posted for formal comment with ballot	July 29 – September 11, 2015

Anticipated Actions	Date
10-day final ballot	October, 2015
NERC Board of Trustees (BOT) adoption	November, 2015

New or Modified Term(s) Used in NERC Reliability Standards

This section includes all new or modified terms used in the proposed standard that will be included in the *Glossary of Terms Used in NERC Reliability Standards* upon applicable regulatory approval. Terms used in the proposed standard that are already defined and are not being modified can be found in the *Glossary of Terms Used in NERC Reliability Standards*. The new or revised terms listed below will be presented for approval with the proposed standard. Upon Board adoption, this section will be removed.

Term(s):

Protection System Coordination Study

An analysis to determine whether Protection Systems for BES Elements [JS1]operate in the intended sequence during Faults.

Protection System Issues Addressed by Other Reliability Standards:

Fault clearing is the only aspect of protection coordination addressed by Reliability Standard PRC-027-1. Including aspects of protection coordination other than Fault coordination would cause duplication or conflict with the requirements of other Reliability Standards. Specifically, other protection issues, such as over/under frequency, over/under voltage, coordination of generating unit or plant voltage regulating controls, and relay loadability are addressed by the following Reliability Standards:

- Underfrequency Load shedding programs are addressed in PRC-006-2.
- Undervoltage Load shedding programs are addressed in PRC-010-1.
- Generator performance during declined frequency and voltage excursions is addressed in PRC-024-1.
- Coordination of Generating Unit or Plant Capabilities, Voltage Regulating Controls, and Protection is addressed in PRC-019-1.
- Transmission relay loadability is addressed in PRC-023-3.
- Generator relay loadability is addressed in PRC-025-1.
- Protective relay response during stable power swings is addressed in PRC-026-1.
- Protection System Misoperations (including those caused by coordination issues) are addressed in PRC-004-3.

When this standard receives Board adoption, the rationale boxes will be moved to the Supplemental Material Section of the standard.

A. Introduction

1. **Title:** **Coordination of Protection Systems for Performance During Faults**
2. **Number:** PRC-027-1
3. **Purpose:** To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Transmission Owner
   4.1.2. Generator Owner
   4.1.3. Distribution Provider (that owns Protection Systems identified in the Facilities section 4.2 below)
   ~~**4.1.3.**~~**4.1.4.** Transmission Planner

   4.2. Facilities: Protection Systems installed to detect and isolate Faults on BES Elements.

5. **Effective Date:** See the Implementation Plan for PRC-027-1, Project 2007-06 System Protection Coordination.

B. Requirements and Measures

Rationale for Requirement R1:[JS2]

Coordinated Protection Systems enhance reliability by isolating faulted equipment, thus reducing the risk of BES instability or Cascading, and leaving the remainder of the BES operational and more capable of withstanding the next Contingency. When Faults occur, properly coordinated Protection Systems minimize the number of BES Elements that are removed from service and protect equipment from damage. The stated purpose of this standard is: "To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those Faults, such that the Protection Systems operate in the intended sequence during Faults." Requirement R1 captures this intent by requiring responsible entities establish a process that, when followed, allows for their Protection Systems to operate in the intended sequence during Faults. Requirement R1, Parts 1.1 through 1.3 are key elements to the process for developing Protection System settings.

Part 1.1 Reviewing and updating the short-circuit models used to develop new or revised Protection System settings helps to assure that settings are developed using accurate, up-to-date information.

Part 1.2 A review of the developed Protection System settings reduces the likelihood of introducing human error and verifies that the settings produced meet the technical criteria of the entity. Peer reviews, automated checking programs, and entity-developed review procedures are all examples of reviews.

Part 1.3 The coordination of Protection Systems associated with BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers) is essential to the reliability of the BES. Communication and review of proposed settings among these entities are necessary to identify potential coordination issues and address the issues prior to implementation of any proposed Protection System changes.

Unforeseen circumstances could require immediate changes to Protection System settings. Requirement R1, Part 1.3.4 requires owners to include a procedure to communicate those unplanned settings changes after-the-fact to the other owner(s) of the electrically-joined Facilities.

Note: In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation.

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for ~~developing new and revised~~performing a Protection System Coordination Study ~~settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults~~[JS3]. The process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

~~1.1. A review and update of short-circuit models for the BES Elements under study.~~[JS4]

~~1.2.~~1.1. ~~A~~ Its method to review ~~of the~~its developed Protection System settings before they are applied.

~~1.3.~~1.2. For its settings for Protection Systems ~~settings applied on~~for [JS5]BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

~~1.3.1.~~1.2.1. Provide the proposed Protection System settings to the owner(s) of the electrically-joined Facilities.

~~1.3.2.~~1.2.2. Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or affirming that no coordination issue(s) were identified.

~~1.3.3.~~1.2.3. Verify that identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.

~~1.3.4.~~1.2.4. Communicate with the other owner(s) of the electrically-joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during:

~~1.3.4.1.~~1.2.4.1. Implementation or commissioning.

~~1.3.4.2.~~1.2.4.2. Misoperation investigations.

~~1.3.4.3.~~1.2.4.3. Maintenance activities.

~~1.3.4.4.~~1.2.4.4. Emergency replacements required as a result of Protection System component failure.

M1. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity established a process to ~~develop settings for its~~perform a Protection System~~s~~ Coordination Study, in accordance with Requirement R1.

Rationale for Requirement R2:

Over time, incremental changes in Fault current can accumulate enough to impact the coordination of Protection System functions affected by Fault current. To minimize this risk, Requirement R2 requires responsible entities (Transmission Owners, Generator Owners, and Distribution Providers) to periodically (1) perform Protection System Coordination Studies and/or (2) review available Fault currents for those Protection System functions listed in Attachment A. The numerical identifiers in Attachment A represent general protective device functions per ANSI/IEEE *Standard C37.2 Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*.

Requirement R2 provides responsible entities with options to assess the state of their Protection System coordination.

Option 1 is a time-based methodology. The entity may choose to perform, at least once every six years, a Protection System Coordination Study for each of its BES Protection Systems identified as being affected by changes in Fault current. The six calendar year time interval was selected as a balance between the resources required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

Option 2 is a Fault current based methodology. If Option 2 is initially selected, Fault current baseline(s) must be established prior to the effective date of this Reliability Standard. A baseline may be established when a new Element is installed or after a Protection System Coordination Study has been performed. The baseline(s) will be used as control point(s) for future Fault current comparisons. The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners and Planning Coordinators. At least once every six calendar years following the effective date of this standard, the entity will perform a Protection System Coordination Study when its Fault current comparison identifies a 15 percent or greater deviation in Fault current values (either three-phase or phase-to-ground) at each bus to which the Element is connected.

The baseline Fault current value(s) will be re-established whenever a new Protection System Coordination Study is performed. Fault current changes on the System not directly associated with BES modifications are usually small and occur gradually over time. The accumulation of these incremental changes could affect the performance of Protection System functions (identified in Attachment A of this standard) during Fault conditions. A Fault current deviation threshold of 15 percent or greater (as compared to the established baseline) and a maximum time interval of six calendar years were chosen for these evaluations. These parameters provide an entity with latitude to choose a Fault current threshold and time interval that best match its protection philosophy, Protection System maintenance schedule, or other business considerations, without creating risk to reliability (See the Supplemental Material section for more detailed discussion).

The footnote in Option 2 describes how an entity may change from a time-based option to a Fault current based option for existing Elements when performing Protection System Coordination Studies. The footnote also allows for the creation of a baseline when a Protection System Coordination Study is performed for installing new Elements.

Option 3 provides the entity the choice of using both the time-based and Fault current based methodologies. For example, the entity may choose to utilize the time-based methodology for Protection Systems at more critical Facilities and use the Fault current based methodology for Protection Systems at other Facilities.

R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element with Protection System functions identified in Attachment A: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

- Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six calendar years; or
- Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater ~~deviation~~ increase[JS6] in Fault current values (for either three-phase or phase-to-ground Faults) at a bus to which the Element is connected, all in a time interval not to exceed six calendar years;~~1~~[JS7] or,
- Option 3: A combination of the above.

M2. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity performed Protection System Coordination Study(ies) and/or Fault current comparisons in accordance with Requirement R2.

~~1 The initial Fault current baseline(s) shall be established by the effective date of this Reliability Standard and updated each time a Protection System Coordination Study is performed. If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new Element, the entity may establish the baseline by performing a Protection System Coordination Study.~~

Rationale for Requirement R3:

Utilizing the processes established in Requirement R1 to develop new and revised Protection System settings provides a consistent approach to the development of Protection System settings and will minimize the potential for errors.

R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1 and one of the options in Requirement R2[JS8] to develop its new and revised settings for Protection System ~~settings~~ for BES Elements. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M3. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that the responsible entity utilized its settings development process established in Requirement R1, as specified in Requirement R3.

Rationale for Requirement R4:

Transmission Planners develop short circuit data bases per MOD-032-1 and utilize them in TPL-001-4 to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt. Since Transmission Planners develop and use short circuit databases, having other entities (TOs, GOs and DPs) use them could introduce errors. Therefore, Transmission Planners are required to calculate all Fault current values (an initial baseline and subsequent periodic updates) and make those available to its Transmission Owners, Generator Owners, and Distribution Providers.

R4. Each Transmission Planner shall calculate the baseline Fault currents for both three-phase and phase-to-ground Faults for all its busses and make such results available its Transmission Owners, Generator Owners, and Distribution Providers. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

4.1. Each Transmission Planner shall annually update the Fault currents for all its busses and make such updates available its Transmission Owners, Generator Owners, and Distribution Providers.

4.1.1. For new busses, the Fault currents initially calculated for that bus shall become its baseline Fault currents.

4.1.2. The Transmission Planner shall reset the baseline Fault currents for any bus when a Fault current (for either a three-phase or phase-to-ground Fault) is greater than or equal to 1.15 times the previously established Fault current baseline has been calculated for that bus.

M4. Acceptable evidence may include, but is not limited to, dated electronic or hard copy documentation to demonstrate that each Transmission Planner made available its initial baseline and its annual updates of Fault current values for all its busses to its

Transmission Owners, Generation Owners, and Distribution Planners, and that it has reset the baseline Fault currents at busses in accordance with part 4.1.1.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority:
As defined in the NERC Rules of Procedure, "Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

1.2. Evidence Retention:
The following evidence retention period(s) identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

The Transmission Owner, Generator Owner, and Distribution Provider shall each keep data or evidence to show compliance with Requirements R1, R2, and R3, and Measures M1, M2, and M3 since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If a Transmission Owner, Generator Owner, or Distribution Provider is found non-compliant, it shall keep information related to the non-compliance until mitigation is completed and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program
As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.1 or Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.1 and Part 1.2.	The responsible entity established a process in accordance with Requirement R1, but failed to include Requirement R1, Part 1.3. OR The responsible entity failed to establish any process in accordance with Requirement R1.
R2.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3 but was late by less than or equal to 30 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 30 calendar days but less than or equal to 60 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 60 calendar days but less than or equal to 90 calendar days.	The responsible entity performed a Protection System Coordination Study for each BES Element, in accordance with Requirement R2, Option 1, Option 2, or Option 3, but was late by more than 90 calendar days. OR The responsible entity failed to perform Option 1, Option

				2, or Option 3, in accordance with Requirement R2.
R3.	N/A	N/A	N/A	The responsible entity failed to utilize the process established in accordance with Requirement R1.

D. Regional Variances

None.

E. Associated Documents

NERC System Protection and Control Subcommittee – "Power Plant and Transmission System Protection Coordination."

NERC System Protection and Control Task Force, December 7, 2006, "Assessment of Standard PRC-001-0 – System Protection Coordination."

NERC System Protection and Control Task Force, September 2006, "The Complexity of Protecting Three-Terminal Transmission Lines."

Version History

Version	Date	Action	Change Tracking
1		Adopted by NERC Board of Trustees	New standard developed under Project 2007-06

Attachment A

The following Protection System functions[2] are applicable to Requirement R2 if available Fault current levels are used to develop the settings for those Protection System functions:

21 – Distance if:

- infeed is used in determining reach (phase and ground distance), or
- zero-sequence mutual coupling is used in determining reach (ground distance).

50 – Instantaneous overcurrent

51 – AC inverse time overcurrent

67 – AC directional overcurrent if used in a non-communication-aided protection scheme

Notes:

1. The above Protection System functions are susceptible to changes in the magnitude of available short-circuit Fault current. These functions utilize current in their measurement to initiate tripping of circuit breakers. The functions listed above are included in a Protection System Coordination Study because they require coordination with other Protection Systems.
2. See the PRC-027-1 Supplemental Material section for additional information.

[2] ANSI/IEEE Standard C37.2 *Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*.

Purpose

The Purpose states: To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults.

Coordinated Protection Systems enhance reliability by isolating faulted equipment, reducing the risk of BES instability or Cascading, and leaving the remainder of the BES operational and more capable of withstanding the next Contingency. When Faults occur, properly coordinated Protection Systems minimize the number of BES Elements that are removed from service and protect equipment from damage. This standard requires that entities establish and implement a process to coordinate their BES Protection Systems to operate in the intended sequence during Faults.

Applicability

Transmission Owners, Generator Owners, and Distribution Providers are included in the Applicability of PRC-027-1 because they may own Protection Systems that are installed for the purpose of detecting Faults on the Bulk Electric System (BES). It is only those Protection Systems that are under the purview of this standard.

Transmission Owners are included in the Applicability of PRC-027-1 because they own the largest number of Protection Systems installed for the purpose of detecting Faults on the BES.

Generator Owners have Protection Systems installed for the purpose of detecting Faults on the BES. It is important that those Protection Systems are coordinated with Protection Systems owned by Transmission Owners to ensure that generation Facilities do not become disconnected from the BES unnecessarily. Functions such as impedance reaches, overcurrent pickups, and time delays need to be evaluated for coordination.

A Distribution Provider may provide an electrical interconnection and path to the BES for generators that will contribute current to Faults that occur on the BES. If the Distribution Provider owns Protection Systems that operate for those Faults, it is important that those Protection Systems are coordinated with other Protection Systems that can be impacted by the current contribution to the Fault of Distribution Provider.

After the Protection Systems of Distribution Providers and Generator Owners are shown to be coordinated with other Protection Systems on the BES, there will be little future impact on the entities unless there are significant changes at or near the bus that interconnects with the Transmission Owner. The Transmission Owner, which is typically the entity maintaining the system model for Fault studies, will provide the Fault current availability upon request by the Distribution Provider or Generator Owner. The Distribution Provider and Generator Owner will determine whether a change in Fault current from the baseline has occurred such that a review of coordination is necessary.

Requirement R1

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults.

The reliability objective of this requirement is to have applicable entities establish a process to develop settings for coordinating their BES Protection Systems, such that they operate in the intended sequence during Faults. The parts that are included as elements of the process ensure the development of accurate settings, as well as providing internal and external checks to minimize the possibility of errors that could be introduced in the development of settings.

This standard references various publications that discuss protective relaying theory and application. The description of "coordination of protection" is from the IEEE Standard C37.113-1999 (Reaffirmed: 2004), *Guide for Protective Relay Applications to Transmission Lines*, which reads:

> *"The process of choosing current or voltage settings, or time delay characteristics of protective relays such that their operation occurs in a specified sequence so that interruption to customers is minimized and least number of power system elements are isolated following a system fault."*

Entities may have differing technical criteria for the development of Protection System settings based on their own philosophies. These philosophies can vary based on system topology, protection technology utilized, as well as historical knowledge; as such, a single definition or criterion for "Protection System coordination" is not practical.

The coordination of some Protection Systems may seem unnecessary, such as for a line that is protected solely by dual current differential relays. However, backup Protection Systems that are enabled to operate based on current or apparent impedance with some definite or inverse time delay must be coordinated with other Protection Systems of the Element such that tripping does not unnecessarily occur for Faults outside of the differential zone.

Part 1.1 A review and update of short-circuit models for the BES Elements under study.

The study used by protection engineers to develop Protection System settings for Transmission Owners, Generator Owners, and Distribution Providers is the short-circuit study. Including a review and, if necessary, an update of short-circuit study information is necessary to ensure that information accurately reflects the physical power system that will form the basis of the Protection System Coordination Study and development of Protection System relay settings. The results of a short-circuit study are only as accurate as the information that its calculations are based on.

A short-circuit study is an analysis of an electrical network that determines the magnitude of the currents flowing in the network during an electrical Fault. Because the results of short-circuit studies are used as the basis for protective device coordination studies, the short-circuit model should accurately reflect the physical power system.

Reviews could include:

1. A review of applicable BES line, transformer, and generator impedances.

2. A review of the network model to confirm the network in the study accurately reflects the configuration of the actual System, or how the System will be configured when the proposed relay settings are installed.
3. A review, where applicable, of interconnected Transmission Owner, Generator Owner, and Distribution Provider information.

Part 1.2 A review of the developed Protection System settings.

A review of the Protection System settings prior to implementation reduces the possibility of introducing human error. A review is any systematic process of verifying the developed settings meet the technical criteria of the entity. Examples of reviews include peer reviews, automated checking programs, and entity-developed review procedures.

Part 1.3 For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

Requirement R1, Part 1.3 addresses the coordination of Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities. Communication among these entities is essential so potential Protection System coordination issues can be identified and addressed prior to implementation of any proposed Protection System changes.

Part 1.3.1 1.3.1. Provide the proposed Protection System settings to the owners of the electrically-joined Facilities.

Requirement R1, Part 1.3.1 requires the entity to include in its process a provision to provide proposed Protection System settings to other entities. This communication ensures that the other entities have the necessary information to review the settings and determine if there are any Protection System coordination issues.

Part 1.3.2 Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any coordination issue(s) or affirming that no coordination issue(s) were identified.

Requirement R1, Part 1.3.2 requires the entity receiving proposed Protection System settings to include in its process a provision to respond to the entity that initiated the proposed changes. This ensures that the proposed settings are reviewed and that the initiating entity receives a response indicating Protection System coordination issues were identified, or affirmation that no issues were identified.

Part 1.3.3 Verify that identified coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.

Requirement R1, Part 1.3.3 requires the entity to include in their process a provision to verify that any identified coordination issue(s) associated with the proposed Protection System settings are addressed prior to implementation. This ensures that any potential impact to BES reliability is minimized.

Note: There could be instances where coordination issues are identified and the entities agree not to mitigate all of the issues based on engineering judgement. It is also recognized that coordination issues identified during a project may not be immediately resolved if the resolution involves additional system modifications not identified in the initial project scope. Further, there could be situations where protection philosophies differ between entities, but the entities can agree that these differences do not create coordination issues.

Part 1.3.4 Communicate with the other owner(s) of the electrically-joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during:

1.3.4.1. Implementation or commissioning.

1.3.4.2. Misoperation investigations.

1.3.4.3. Maintenance activities.

1.3.4.4. Emergency replacements required as a result of Protection System component failure.

Requirement R1, Part 1.3.4 requires the entity to communicate revisions to Protection System settings that occur due to unforeseen circumstances and differ from those developed during the planning stages of projects.

Requirement R2

This requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element with Protection System functions identified in Attachment A:

- Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six calendar years; or
- Option 2: Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the Element is connected, all in a time interval not to exceed six calendar years;[3] or,
- Option 3: A combination of the above.

Over time, incremental changes in Fault current can accumulate enough to impact the coordination of Protection System functions affected by Fault current. To minimize this risk, Requirement R2 requires responsible entities to periodically (1) perform Protection System Coordination Studies and/or (2) review available Fault currents for those Protection System functions listed in Attachment A. Two triggers were established for initiating a review of existing Protection System settings to allow for industry flexibility.

[3] The initial Fault current baseline(s) shall be established by the effective date of this Reliability Standard and updated each time a Protection System Coordination Study is performed. If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new Element, the entity may establish the baseline by performing a Protection System Coordination Study.

In the first option, an entity may choose a time-based methodology to review Protection System settings, thus eliminating the necessity of establishing a Fault current baseline and periodically performing Fault current comparisons. This option provides the entity the flexibility to choose an interval of up to six calendar years for performing the Protection System Coordination Studies for those Protection System functions in Attachment A. The six-calendar-year time interval was selected as a balance between the manpower required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

The second option allows the entity to periodically check for a 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at each bus to which an Element is connected. This option allows the entity to choose an interval of up to six calendar years to perform the Fault current comparisons and Protection System Coordination Studies. The six-calendar-year time interval was selected as a balance between the manpower required to perform the studies and the potential reliability impacts created by incremental changes of Fault current over time.

The accumulation of these incremental changes could affect the performance of Protection Systems during Fault conditions. A maximum Fault current deviation of 15 percent (when compared to the entity-established baseline) was established based on generally-accepted margins for setting Protection Systems in which incremental Fault current changes would not interfere with coordination. The 15 percent maximum deviation provides an entity with latitude to choose a Fault current threshold that best matches its protection philosophy, or other business considerations. The Fault current based option requires an entity to first establish a Fault current baseline to be used as a point of reference for future Fault current studies. The Fault current values used in the percent change calculation, whether three-phase or phase-to-ground Fault currents, are typically determined with all generation in service and all transmission BES Elements in their normal operating state.

An entity that elects to use Option 2 following the effective date of the standard, must establish its baseline prior to the effective date. If an initial baseline was not established by the effective date of this Reliability Standard because of the previous use of an alternate option or the installation of a new Element, the entity may establish the baseline upon performing a Protection System Coordination Study. The Fault current values used in the original baseline can be updated or created when a Protection System Coordination Study is performed. The baseline values at each bus to which an Element is connected are updated whenever a new Protection System Coordination Study is performed for the subject Protection System.

> **Example:** An initial baseline is established at 10,000 amps. During the first short-circuit review, it is discovered that Fault current has increased to 11,250 amps (12.5 percent change); consequently, no Protection System Coordination Study is required since the increase is below the maximum 15 percent deviation. The baseline value for the next study remains at 10,000 amps because no study was performed. However, during the next Fault current comparison, the Fault current has increased to 11,500 (15 percent change); therefore, a Protection System Coordination Study is required, and a new baseline of 11,500 amps would be established.

> **Note:** In the first review described above, if the entity decides to perform a Protection System Coordination Study at the 12.5 percent deviation and the results of the study indicate that the settings still meet the setting criteria of the entity, then no settings changes are required and the baseline Fault current(s) would be updated.

As a third option, an entity has the flexibility to apply a combination of the two methodologies. For example, an entity may choose the periodic Protection System review (Option 1) and review its Facilities operated above 300 kV on a six year interval, while choosing to use the Fault current comparison (Option 2) for its Facilities operated below 300 kV.

Attachment A identifies the Protection System functions susceptible to changes in the magnitude of available short-circuit Fault current. These functions utilize AC current in their measurement to initiate tripping of circuit breakers. The numerical identifiers in Attachment A represent general device functions according to *ANSI/IEEE Standard C37.2 Standard for Electrical Power System Device Function Numbers, Acronyms, and Contact Designations*. The device functions listed in Attachment A are to be reviewed provided they require coordination with other Protection Systems. The following scenarios provide some examples for applying Attachment A.

A "51 – AC inverse time overcurrent" relay connected to a CT on the neutral of a generator step-up transformer, referred to as "51N – AC Inverse Time Earth Overcurrent Relay (Neutral CT Method)" in ANSI/IEEE Standard C37.2, would be included in a Protection System Coordination Study. Also applicable, are "51 – AC Inverse time overcurrent" relays connected to CTs on the phases of an autotransformer for through-fault protection. Overcurrent functions used in conjunction with other functions are to be reviewed as well. An example is a definite-time overcurrent function, which is a "50 – Instantaneous overcurrent" function used in conjunction with a "62 – Time-delay" function.

If the functions listed in Attachment A are used in conjunction with other functions, they would be included in a Protection System Coordination Study provided they require coordination with other Protection Systems. An example of this is a time-delayed "21 – Distance" function, which is a "21 – Distance" function with a "62 – Time-delay" function. Another example would be a definite-time overcurrent function, which is a "50 – Instantaneous overcurrent" function with a "62 – Time-delay" function. A "50 – Instantaneous overcurrent" function used for supervising a "21 – Distance" function would <u>not</u> be included in a Protection System Coordination Study as it does not require coordination with other Protection Systems.

Reviewing "21 – Distance" functions is limited to those applied for phase and ground distance where infeed is used in determining the phase or ground distance setting when zero-sequence mutual coupling is used in determining the setting. Where infeed is <u>not</u> used in determining the setting, "21 – Distance" functions would <u>not</u> be included in a Protection System Coordination Study, as the reach is not susceptible to changes in the magnitude of available short-circuit Fault current. Where infeed is used in determining the reach, coordination can be affected by changes in the magnitude of available short-circuit Fault current. Two examples where infeed may be used in determining the reach, are protection for a transmission line with a long tap and a three-terminal transmission line. Ground distance functions are influenced by zero-sequence mutual coupling. The ground distance measurement can appear to be greater than or less than the true distance to a Fault when there is zero-sequence mutual coupling. The influence of zero-sequence mutual coupling changes with the magnitude of available short-circuit current. Therefore, “21 – Distance” functions would be included in a Protection System Coordination Study, when zero-sequence mutual coupling is used in determining the setting.

Requirement R3

The requirement states: Each Transmission Owner, Generator Owner, and Distribution Provider shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements.

The reliability objective of this requirement is for applicable entities to utilize the process established in Requirement R1. Utilizing each of the elements of the process ensures a consistent approach to the development of accurate Protection System settings, decreases the possibility of introducing errors, and increases the likelihood of maintaining a coordinated Protection System.

Rationale

During development of this standard, text boxes were embedded within the standard to explain the rationale for various parts of the standard. Upon BOT adoption, the text from the rationale text boxes will be moved to this section.

Question:

2. Do you agree with the proposed Implementation Plan? If not, please provide the basis for your disagreement and your proposed revisions.

Possible Answers

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